**South Carolina Public Service Commission**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Exhibit TF-1**

**Tyler Fitch *curriculum vitae***

# Tyler J. Fitch

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## EDUCATION

Master of Science in Natural Resources, focus in Energy Policy. *School for the Environment and Sustainability, University of Michigan,* 2018.
Bachelor of Science in Environmental Sciences. *University of North Carolina at Chapel Hill*, 2013.

## PROFESSIONAL EXPERIENCE & RELEVANT WORK

***Vote Solar.*** **Regulatory Manager, Southeast.** *August 2018 – Present.* Expert testimony and regulatory policy analysis supporting Vote Solar's vision of a cleaner, more equitable energy system. Thought leadership on rate design and climate risk. Analysis and testimony at regulatory commissions in Virginia, North Carolina, South Carolina, Georgia, Florida, New Orleans, Arizona, and Michigan since August 2018.

***Environmental Defense Fund.*** **Climate Corps Fellow.** May – August 2017 & 2018. Quantitative analysis and comment drafting on behalf of Environmental Defense Fund and Citizens Utility Board to Illinois Power Agency's Request for Comments on the Long-Term Renewable Resources Procurement Plan (LTRRPP). Led program development on Environmental Defense Fund and the Accelerate Group's *SolarInTheCommunity.com* platform.

***Southern California Edison.*** **Graduate Consultant.** *August – December 2016.* Assisted in market valuation study for electrification in SCE service territory.

***ICF International.*** **Research Analyst.** *October 2013 – June 2016*. Technical & quantitative analysis for federal, state, and local energy efficiency programs. Served as Multifamily Technical Lead for the Department of Energy Better Buildings Challenge, 2015-2016. Provided quantitative support for President Barack Obama's 2015 Remarks on the Better Buildings Challenge. Led policy design and implementation for the City of Cambridge, MA's Building Energy Use Disclosure Ordinance (BEUDO).

## REGULATORY & RULEMAKING PARTICIPATION

- ***Supporting Analysis.*** Florida Public Service Commission. Docket No. 20200151-EI. Gulf Power Company's Petition for Approval of a Regulatory Asset to Record Costs Incurred Due to COVID-19.
- ***Supporting Analysis.*** Virginia State Corporation Commission. Docket No. PUR-2020-00048. Ex Parte: Temporary Suspension of Utility Service Disconnections.
- ***Supporting Analysis***. Public Service Commission of South Carolina. Docket No. 2020-106-A. Actions in Response to COVID-19.

- ***Expert Testimony.*** Virginia State Corporation Commission. Case No. PUR-2019-00214. Application of Virginia Electric and Power Company for approval to establish an experimental residential rate, designated Time-of-Use Rate Schedule 1G
- ***Expert Testimony.*** North Carolina Utilities Commission, Docket Nos. E-7, Sub 1214 and D-2, Sub 1219. Duke Energy Carolinas and Duke Energy Progress Rate Cases.
- ***Expert Testimony.*** Georgia Public Service Commission, Docket #42516. Georgia Power Rate case. December 2019.
- ***Comments Submitted.*** North Carolina Department of Environmental Quality. Submitted comments on Draft Clean Energy Plan. September 2019.
- ***Supporting Analysis.*** Florida Public Service Commission 20190061-EI. FPL SolarTogether Proposal. Supporting analysis for testimony of William M. Cox. September 2019.
- ***Comments Submitted.*** City of New Orleans Docket No. UD-19-01. Proceeding to Establish Renewable Portfolio Standards. Submitted comments June 2019.
- ***Supporting Analysis.*** Arizona Corporation Commission Docket No. RU-00000A-18-0284. Modifications to the Commission's Energy Rules. Supporting analysis for Joint Stakeholder Proposal for New Energy Rules. June 2019.
- ***Supporting Analysis.*** Georgia Public Service Commission Docket 42310 &42311. Georgia Power Company's 2019 Integrated Resource Plan. Supporting analysis for testimony of William M. Cox. April 2019.
- ***Supporting Analysis.*** Florida Public Service Commission 20180204-EI. TECO Shared Solar Tariff. Supporting analysis and drafting for Vote Solar's Comments. April 2019.
- ***Supporting Analysis.*** South Carolina Public Service Commission No. 2018-318/9-E. Duke Energy Progress/Carolinas Rate Cases. Supporting analysis for testimony of Justin Barnes. March 2019.
- ***Supporting Analysis.*** Michigan Public Service Commission Case No. U-20162. DTE Energy Rate Case. Supporting analysis for testimony of Will Kenworthy. November 2018.
- ***Supporting Analysis.*** Virginia Electric and Power Company Case No. PUR-2018-00100. Supporting analysis for testimony of Caroline Golin. October 2018.

**PUBLICATIONS**

- Fitch, T. Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resources Plan.
- Fitch, T. 10 Principles for Duke's Integrated Resoruce Plans in the Public Interest. August 2020.
- Fitch, T. The State of Rooftop Solar in Florida. *Vote Solar.* August 2020.
- Fitch, T. Principles for Protecting Electric Utility Customers in the Regulatory Response to COVID-19. *Vote Solar.* August 2020.

- Fitch, T. The Costs & Risks of Florida's Dependence on Natural Gas. *Vote Solar.* July 2020.
- Fitch, T. COVID-19 and the Utility Bill Debt Crisis. *Vote Solar.* April 2020.
- Fitch, T. "Understanding Electric Utility Ratemaking, Rate Design, and the Value of Clean Energy." Presentation given at Southface Energy Institute, February 2019.
- Fitch, T. (2018, April) Islands of Light: Microgrids and the Public Good. *Agora Planning Journal,* 12, 74-80.
- Vanderwilde, C., Fitch, T., Mueller, E., (2018, April). Fueling a Transition: Evaluating the Feasibility of a Hybrid Renewable Microgrid in Beni, Democratic Republic of Congo, manuscript. University of Michigan School for the Environment and Sustainability.
- Fitch, T., Lenhart, A., Buchanan, C., Jeong, B. (2018, January). Get Free: Understanding the Potential for Community Solar Power in Highland Park. Dow Sustainability Fellow Report Series.
- Fitch, T., (2017, September). "How Illinois is working toward a cleaner, more equitable energy future." EDF Energy Exchange.
- Fitch, T., (2016, December). "Closing the Adoption Gap: Affordable Solar Power and Energy Justice." University of Michigan School of Natural Resources & Environment Policy Brief Series.

## **HONORS / AWARDS**

Clean Energy Leadership Institute Fellow, 2019
Peter & Carolyn Mertz Fellow, 2018
UNLEASH Lab Climate Action Runner-up, 2018
Presenter at Sustainable Energy Transitions Initiative, 2018
University of Michigan Delegate to UNFCCC COP 23, 2017
Environmental Defense Fund Climate Corps Advocacy Fellow, 2017
Dow Sustainability Fellow, 2017
University of Michigan Academic Leadership Fellow, 2016
ICF International Project of the Year, 2016

**South Carolina Public Service Commission**

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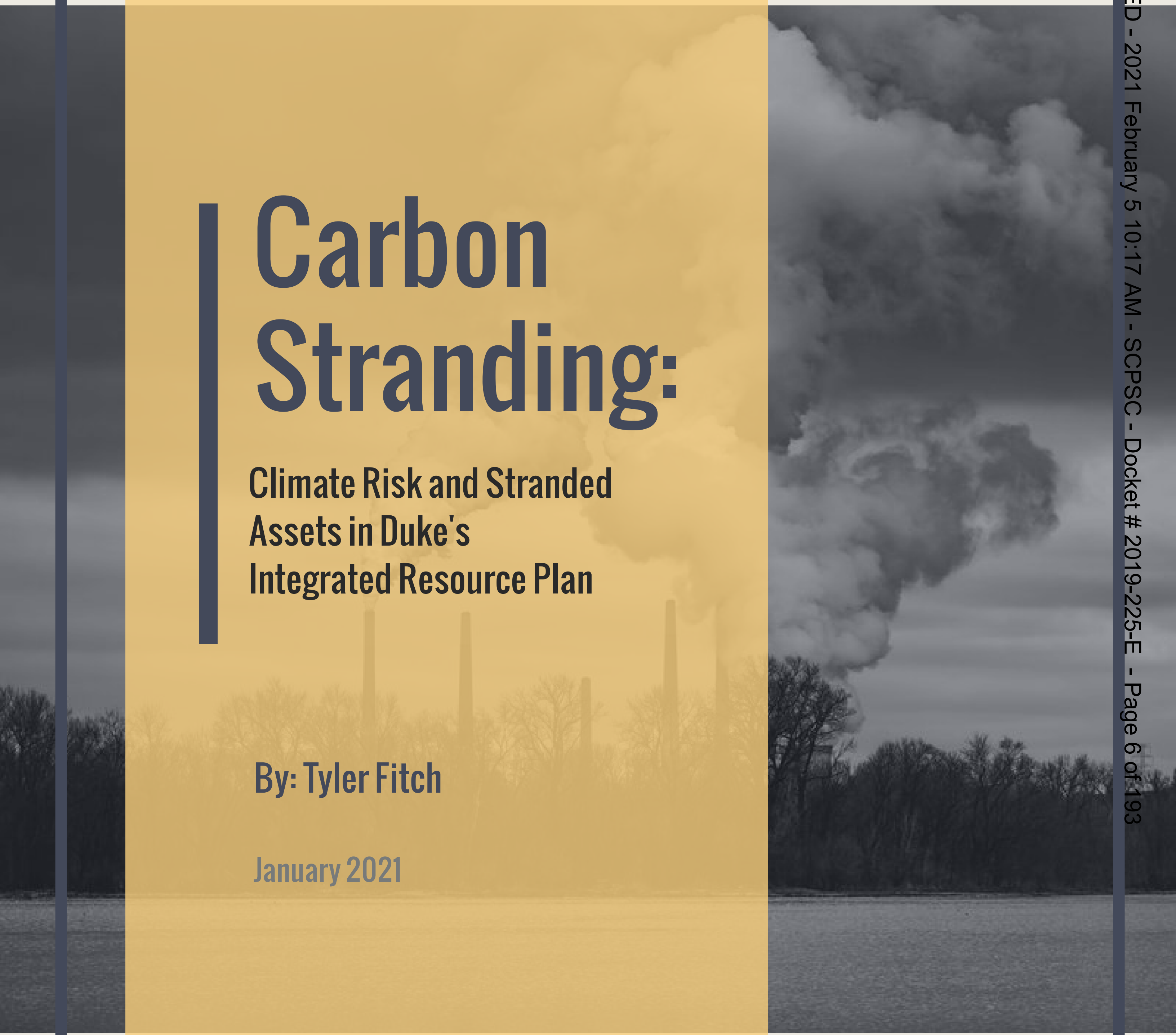
**Exhibit TF-2**

# Carbon Stranding: Climate Risk and Stranded Assets in Duke's Integrated Resources Plan

Energy Transition Institute

www.energytransitions.org



# Carbon Stranding:

## Climate Risk and Stranded Assets in Duke's Integrated Resource Plan

By: Tyler Fitch

January 2021

Exhibit TF-2

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**Tyler Fitch** is regulatory manager for the Southeast at Vote Solar, where he conducts regulatory analysis and expert testimony on utility rate design and climate risk. He received a Master's of Science in Environmental Policy from the University of Michigan's School for the Environment and Sustainability in May 2018.

## Executive Summary

Climate change is disrupting the electric utility industry, and electric utilities and the regulators who oversee them must adapt. When utilities craft their integrated resource plans—15-year future roadmaps for new investments in power generation—it is critical that they address the physical, regulatory, economic, and financial impacts of changes to our climate and the emerging social and economic response. Given the decades-long lifetime of new power plants, investments made now will face climate-related stresses, shocks, and pressures that are substantially stronger than those experienced today. If integrated resource plans do not respond to this reality, utilities and regulators risk approving a plan that does not provide the most affordable, reliable, and sustainable electricity for their customers. Ultimately, ratepayers bear the burden of paying for integrated resource planning that is not sufficiently resilient to climate-related risks and opportunities.

This report examines utility integrated resource planning in light of climate-related risks and opportunities. Specifically, the report assesses the climate-related risks to investments in new fossil-fueled power plants, including being outcompeted by new, economically competitive technology, affected by climate-amplified physical phenomena, or rendered unusable because of constraints on carbon emissions. Investments that are brought offline before the end of their planned life in this way are referred to as 'stranded' assets, because the utility is unable to realize some of the expected value of their investment when it is unable to be operated as expected. Although the burden of stranded asset costs should be borne by utility shareholders in the abstract, stranded asset costs are more often assigned to ratepayers in practice.

Duke Energy Corporation's 2020 Integrated Resource Plans in North and South Carolina provide helpful case studies for assessing the risk of stranded assets. The Plans are the first filed in the Carolinas since Duke Energy's September 2019 commitment to reach net-zero carbon emissions by 2050, and regulators, legislators, and executive agencies across both states have indicated an elevated interest in climate-related risks and opportunities. Climate-related risks to carbon-emitting generation



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notwithstanding, the Plans contemplate a 9.6 gigawatt addition of new gas-fired generation capacity in their baseline scenarios – one of the largest proposed expansions of fossil generation capacity of any utility in the United States.

Under climate-related risks, expanded investment in carbon-emitting generation could pose new risks to ratepayers. The report uses the term **'carbon stranding'** to refer to generation assets that would need to be either run less frequently or removed from the portfolio altogether in order to comply with carbon constraints. In this case, applicable carbon constraints are Duke Energy's corporate carbon commitment and the carbon emissions goals articulated by the state of North Carolina. While carbon commitments are just one of several vectors of climate-related risks and potential for stranding to these investments, it is used in this analysis as a proxy for climate risk generally.

The carbon stranding analysis conducted in this report finds that if Duke Energy pursues the investment plan contemplated in its Integrated Resources Plan, a substantial portion of its power plant fleet will need to be taken offline to meet existing carbon commitments. Without regulatory intervention, ratepayers will continue to pay off these plants for decades, even while they remain neither used nor useful. Carbon stranding costs to ratepayers are on the order of tens or hundreds of millions of dollars per year. In total, this analysis finds that carbon stranding costs from existing and proposed investments in these Integrated Resource Plans will be **$4.8 billion, or $900 in present-value costs for every residential Duke Energy customer in the Carolinas.**

Key findings of this report are below:

- **Stranded assets represent a salient risk for ratepayers.** Utilities are typically required to prove that their assets are 'used and useful' in order to be able to profit from their investment. In practice, however, utilities have enjoyed a presumption of used and usefulness. Even as the cost decline of renewables renders the fossil plants uneconomic, utility managers are incented to keep emitting resources online as long as possible. Although utility management is aware of the potential for stranded assets, utility executives and shareholders have generally expressed confidence that the burden for paying stranded asset costs will lie with ratepayers.

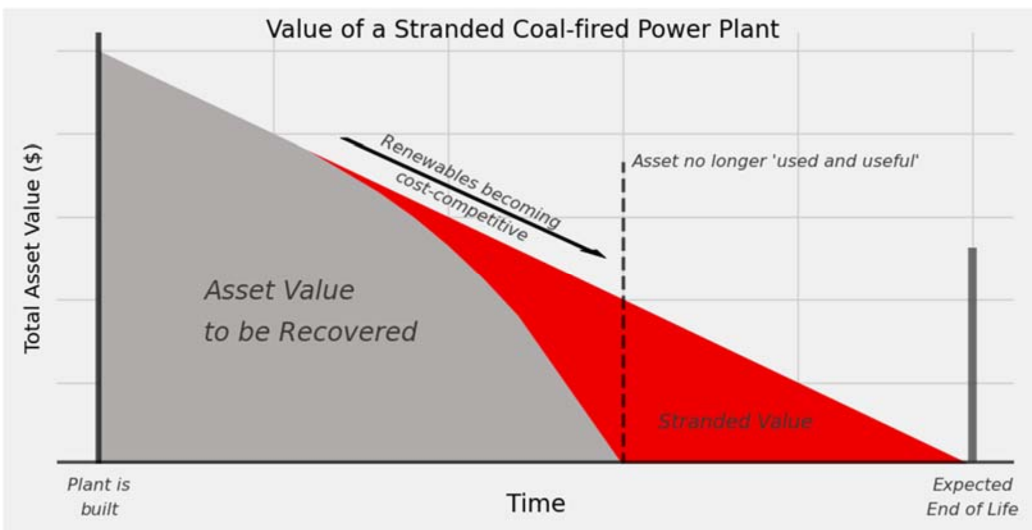


***Figure ES-1.*** *Asset value over time for a hypothetical stranded asset*

- **Climate-related risks are increasingly shaping the present and future of the electricity grid.** Physical, financial, economic, regulatory, and reputational risks are material risks for Duke's operating companies in the Carolinas.

**Table ES-1.** *Summary of Climate-related Risks for Duke Energy's Companies in the Carolinas*

| Type of Risk | Duke Energy Exposure in Carolinas |
|---|---|
| **Physical** | 2020 North Carolina Climate Science Report found that "large changes in North Carolina's climate, much larger than at any time in the state's history, are ***very likely.***"[1] A Moody's analysis found Duke among the most at-risk utilities to flooding.[2] |
| **Financial** | BlackRock, Duke Energy Corporation's third-largest shareholder, claims climate risks are driving a "fundamental reshaping of finance."[3] The firm voted against boards of directors 55 times during 2019-2020 due to lack of climate progress.[4] Increased focus on environmental, social, & governance (ESG) issues are driving Duke investor attention.[5] |
| **Economic** | Renewable energy technologies are outcompeting conventional fossil-fueled generation, even on a subsidy-free basis.[6] Expert analysis finds that portfolios of clean energy resources could economically out-compete existing fossil generation by the mid-2020s.[7] |
| **Regulatory** | North Carolina's Clean Energy Plan contemplates future policies to decarbonize the electric power sector, including accelerated coal retirements, market-based carbon reduction programs, clean energy standards, or a combination of these standards.[8] |
| **Reputational** | Duke Energy's existing decarbonization goals are a public commitment, and the corporation's reputation and social license could be damaged if the commitment is not upheld. In a recent survey, Deloitte found that "the math doesn't add up" for Duke's decarbonization plan.[9] |

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[1] Kunkel, K.E., D.R. Easterling, A. Ballinger, S. Bililign, S.M. Champion, D.R. Corbett, K.D. Dello, J. Dissen, G.M. Lackmann, R.A. Luettich, Jr., L.B. Perry, W.A. Robinson, L.E. Stevens, B.C. Stewart, and A.J. Terando, (2020). North Carolina Climate Science Report. North Carolina Institute for Climate Studies, 233 pp. Retrieved at: https://ncics.org/nccsr.

[2] Morehouse, C., (2020, January). "Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's." *Utility Dive*. Retrieved at: https://www.utilitydive.com/news/ameren-xcel-dominion-duke-among-most-at-risk-from-changing-climate-mood/570789/.

[3] Fink, L. (2020). A Fundamental Reshaping of Finance. *BlackRock.* Retrieved at: https://www.blackrock.com/us/individual/larry-fink-ceo-letter.

[4] Partridge, J., (2020, September). "BlackRock votes against 49 companies for lack of climate crisis progress." *The Guardian.* Retrieved at: https://www.theguardian.com/business/2020/sep/17/blackrock-votes-against-49-companies-for-lack-of-climate-crisis-progress.

[5] Duke Energy Carolinas (2020, September). Duke Energy Carolinas Integrated Resource Plan 2020 ("DEC IRP Report"). NCUC Docket No. E-100, Sub 165. p. 93.

[6] Lazard, (2020, October). Levelized Cost of Energy and Levelized Cost of Storage — 2020. Retrieved at: https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/.

[7] Teplin, C., Dyson, M., Engel, A., Glazer, G., (2019). The Growing Market for Clean Energy Portfolios. Rocky Mountain Institute. Retrieved at: https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/.



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- **The economic and policy context for Duke Energy's 2020 Integrated Resource Plans (IRPs) is cause for greater focus on a climate-resilient path.** Concern around climate-related risks have increased at the state and national level since Duke Energy's 2018 IRPs in the Carolinas. Legislation in South Carolina and executive action in North Carolina are driving increased scrutiny on resource planning, and the North Carolina Utilities Commission acknowledged the risks of stranded assets in its response to a 2019 update of the 2018 IRPs.[10] The 2020 IRPs are also the first in the Carolinas since Duke Energy's corporate net-zero carbon commitment.

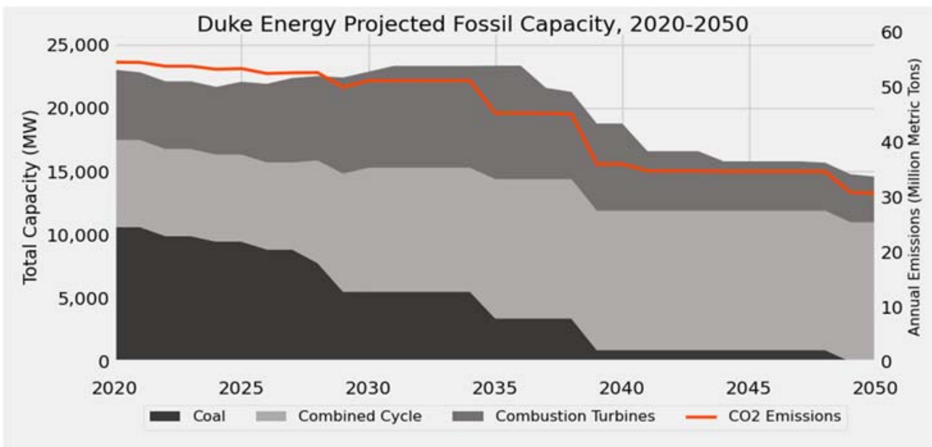


***Figure ES-2.*** *Duke Energy Projected Fossil Capacity and Emissions, 2020-2050. The shaded areas represent operating capacity, in megawatts, of Duke's generation portfolio in the Carolinas (for context, peak coincident load in the Carolinas is approximately 25,000 megawatts[11]). The yellow line projects carbon emissions over time, declining from over 50 million metric tons in 2020 to about 30 million metric tons in 2050. Further explanation is provided in Section D of this report.*

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[8] North Carolina Department of Environmental Quality ("NC DEQ") (2019, October). North Carolina Clean Energy Plan Policy & Action Recommendations. Retrieved at: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[9] Porter, S., Thomson, J., & Motyka, M., (2020, September). Utility decarbonization strategies: Renew, reshape, and refuel to zero. *Deloitte*. Retrieved at: https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/utility-decarbonization-strategies.html.

[10] North Carolina Utilities Commission ("NCUC") (2020, April). Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans. Docket No. E-100, Sub 157. Retrieved at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568c4d0983.

[11] Matsuda-Dunn, R., Emmanuel, M., Chartan, E., Hodge, B., & Brinkman, G., (2020, January). Carbon-Free Resource Integration Study. *National Renewable Energy Laboratory.* Retrieved at: https://www.nrel.gov/docs/fy20osti/74337.pdf.



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- **Duke Energy's 2020 Integrated Resource Plans maintain a similar level of carbon-emitting generation capacity through 2035, and much remains online through and past 2050.** While the Integrated Resource Plans contemplate retiring most of the existing coal fleet by 2030, these reductions in fossil capacity are offset by new investment in gas-fired combustion turbines and combined-cycle plants. If the Duke companies continue to operate their fleet as they have historically, the emissions trajectory of Duke Energy's operating companies in the Carolinas will be increasingly inconsistent with Duke Energy's corporate climate commitments. Duke Energy's emissions in the Carolinas will decline about 40 percent by 2050, from 50 million tons of carbon emitted in 2020 to just over 30 million metric tons in 2050. Notably, these totals do not include upstream emissions occurring during methane production and transport. Although the Duke plans include a high-level discussion of carbon-neutral retrofits to their gas-fired assets, including green hydrogen and carbon capture and storage, the IRPs do not include any plans to deploy these technologies or discuss any costs they might incur to ratepayers.

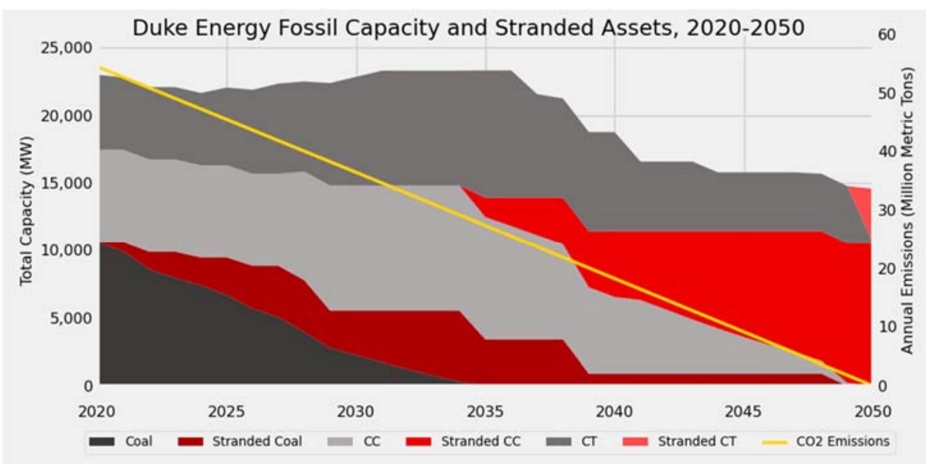


*Figure ES-3. Duke Energy portfolio, with carbon stranded assets to meet climate commitments. In this case, fossil units were removed from operation to comply with Duke Energy's carbon commitments. Black and gray shaded areas represent operating fossil capacity, by technology. Areas shaded red represent units that have been taken offline before the end of their engineering lifetime to meet carbon commitments. The yellow line shows the carbon trajectory of the portfolio, starting at over 50 million metric tons per year and declining toward zero. Further explanation is provided in Section D of this report.*

- **To meet Duke Energy Corporation's corporate climate commitment,** carbon-emitting plants within the Duke Energy fleet in the Carolinas will either need to decrease their usage rate or be pulled out of operation altogether.[12] This includes removing coal entirely from the portfolio in the early 2030s and stranding even recently built combined-cycle plants through the 2030s and 2040s. In this model, combustion turbines are preserved to address resource adequacy concerns and they are allowed to stay online through much of the 2040s (combustion turbines tend to run only during peak demands conditions, and therefore do not contribute as much to total carbon emissions).

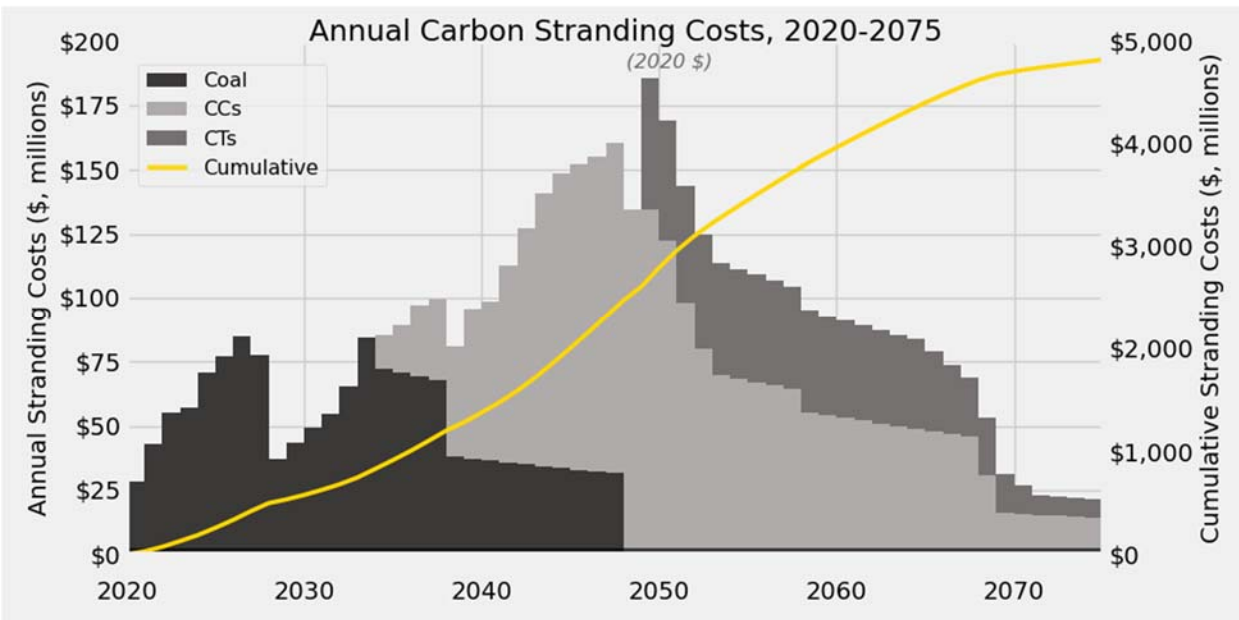


***Figure ES-4.*** *Annual and Cumulative Carbon Stranding Costs, 2020-2075. Bar graphs represent costs of stranded capacity per year, by technology, in millions of dollars. Costs are in the tens of millions through 2030, then increase to as much as $175 million. The yellow line shows cumulative stranded costs, reaching about $4.8 billion. Further explanation is provided in Section D of this report.*

- **These costs are meaningful to ratepayers.** Potential carbon stranding costs to ratepayers are on the order of tens or hundreds of millions of dollars per year. Over the course of these assets'

[12] For the purposes of this analysis, a zero-carbon goal is contemplated rather than a net-zero carbon goal. The availability, costs, and quality of carbon offsets through mid-century are not known; the most certain way to achieve net-zero carbon operations is to achieve gross zero-carbon operations.

lifetimes, ratepayers could pay more than **$4.8 billion** in 2020 dollars for stranded assets. This amount exceeds the total stranded costs to Dominion and Duke Energy combined on the Atlantic Coast Pipeline by more than $1 billion. In present value terms, this is equivalent to a cost of **over $900 per Duke customer in the Carolinas**. Because the planned lifetimes for new power plants often span several decades, cost impacts are incurred through 2074.

**Table ES-2.** *Key Results of Duke Energy Carbon Stranding Analysis*

| | |
|---|---|
| **Projected GHG Emissions Overshoot in 2050** | 30 million metric tons |
| **Engineering lifetime of new-build combined-cycle gas plants** | 40 years |
| **Projected operational lifetime of new-build combined-cycle gas plants** | 12.3 years |
| **Total Carbon Stranding Costs** *(2020 $)* | $4.8 billion |
| **Present-Value Carbon Stranding Costs** *(2020 $)* | $3.3 billion |
| **Present-Value Cost per Residential Duke Customer** | $916.93 |

- **Utilities and regulators have tools at their disposal to avoid these costs.** While Duke Energy has begun to incorporate climate risks into its corporate governance, risk assessment can and should be extended downward to the operating company level and be explicitly addressed in integrated resource planning. Similarly, utilities can explicitly integrate corporate carbon commitments into their planning processes. Accordingly, utilities should explicitly discuss end-of-life plans (including accelerated retirement or retrofits for carbon capture) and attendant costs for carbon-emitting assets, even if their actual lifetime is uncertain. Regulators can provide certainty by affirmatively finding that climate-related risks are material and that a consideration of climate-related risks is a necessity for prudent management.

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## Tables and Figures





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## Introduction

Climate change, and society's response to it, are set to shape the US energy and economic landscape in the 21st century. Major economic and financial institutions are taking note: The US Commodities Future Trading Commission released a groundbreaking report in September 2020 finding that "climate change poses a major risk to the stability of the US financial system and to its ability to sustain the American economy."[13] These trends have caused major banks and asset managers, from JPMorgan Chase[14] to BlackRock,[15] to make commitments to remove climate risk from their portfolio and ensure their portfolios are decarbonizing.

Adjusting to climate change will have deep implications for our electric utilities, a capital-heavy sector responsible for a substantial portion of US carbon emissions and poised to become a linchpin of the zero-carbon economy.[16] Electric utilities are likely to face risks if they are unable or unwilling to decarbonize generation fleets, but the transition to clean energy also holds opportunities: renewable power technologies like wind and solar have continued their unprecedented cost decline, and the International Energy Agency declared in its World Energy Outlook 2020 that solar power had become the "cheapest electricity in history."[17]

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[13] US Commodities Future Trading Commission (2020, September). Managing Climate Risk in the US Financial System. Retrieved at: https://www.cftc.gov/sites/default/files/2020-09/9-9-20%20Report%20of%20the%20Subcommittee%20on%20Climate-Related%20Market%20Risk%20-%20Managing%20Climate%20Risk%20in%20the%20U.S.%20Financial%20System%20for%20posting.pdf.

[14] Benoit, D., (2020, October). "JPMorgan Pledges to Push Clients to Align With Paris Climate Agreement." *Wall Street Journal.* Retrieved at: https://www.wsj.com/articles/jpmorgan-pledges-to-push-clients-to-align-with-paris-climate-agreement-11602018245.

[15] Fink, L. (2020, January). A Fundamental Reshaping of Finance. BlackRock. Retrieved at: https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter.

[16] Mahajan, M., (2019, November). "How To Reach U.S. Net Zero Emissions By 2050: Decarbonizing Electricity." *Forbes.* Retrieved at: https://www.forbes.com/sites/energyinnovation/2019/11/12/how-to-reach-us-net-zero-emissions-by-2050-decarbonizing-electricity/#59f08aa649e7.

[17] Carbon Brief (2020, October). "Solar is now 'cheapest electricity in history', confirms IEA." Retrieved at: https://www.carbonbrief.org/solar-is-now-cheapest-electricity-in-history-confirms-iea.

Like their financers, major US electric utilities have taken note and made bold announcements on their intentions to transition to net-zero carbon energy: between 2018 and 2020, nearly all major US utilities announced a commitment to deeply cutting their emissions to zero or near zero by 2050.[18] But to date, these utilities' investment plans in new fossil generation have not always matched their climate action ambitions. A September 2020 Deloitte study noted that for many utilities, the 'math doesn't yet add up' for utility decarbonization goals,[19] and one watchdog even found that the pace of decarbonization was slated to slow across many utilities in the 2030s.[20]

Duke Energy's 2020 Integrated Resource Plans (IRPs) in the Carolinas present a case study to better understand tensions between corporate climate commitments and short-term investment plans. The 2020 IRPs are Duke Energy's first in the Carolinas since their net-zero-by-2050 commitment, but the plans entail an expansion of fossil-fueled power capacity through the 2030s, rather than a drawdown.

This discrepancy raises deep questions about the nature of the energy transition. What is the relationship between a utility's 30-year commitment to decarbonize and its 15-year integrated resource planning horizon? How should regulators treat corporate climate commitments as they weigh whether the plan is in the public interest? What is the likelihood that these plants are shut down midway through their operational lives (some of which extend into the 2070s)? What are the typical regulatory standards used for allocating these costs, and will they be useful in the context of climate-related changes? These are relevant questions, not only for utilities, their regulators, and advocates, but also for ratepayers and members of the public invested in a climate-resilient economy.

This report explores these questions and assesses how—as a result of Duke's 2020 Carolinas IRPs—ratepayers may be burdened with the fallout from climate-related risks. **Section A** provides background

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[18] Gearino, D., (2020, October). "Inside Clean Energy: Net Zero by 2050 Has Quickly Become the New Normal for the Largest U.S. Utilities." *InsideClimateNews.* Retrieved at: https://insideclimatenews.org/news/30092020/inside-clean-energy-net-zero-2050-utilities.

[19] Deloitte.

[20] Pomerantz, D., (2019, June). Utility Carbon Targets Reflect Decarbonization Slowdown In Crucial Next Decade. Energy and Policy Institute. Retrieved at: https://www.energyandpolicy.org/utility-carbon-targets/.

on the regulatory constructs that determine how utilities plan generation, construct energy prices, and recover money they have invested in long-lived assets. **Section B** explores the multiple dimensions of climate-related risks that affect the electric utility industry in general and Duke Energy's Carolinas footprint in particular. **Section C** provides an overview of Duke Energy's current generation fleet in the Carolinas and the proposals in its 2020 Integrated Resources Plans (IRPs). **Section D** quantifies the potential costs of ratepayers due to "carbon stranded" assets. Finally, **Section E** provides conclusions and policy recommendations.

## A. Primer on Utility Generation Planning in the Southeast

The Eastern Interconnection is a connected electricity mega-grid that spans from Key West to Manitoba and has continually provided power to households across the United States since 1967. It is part of the bedrock of modern life in the Eastern half of North America.[21] In fact, the growth of the electricity grid across the United States has been called the single greatest engineering achievement of the 20th century by the National Academy of Engineering.[22] But the modern electricity grid is more than a feat of engineering; it also relies on a complex set of legal, regulatory, and economic relationships and incentives that ensure decisions made on the electricity grid serve the public interest. The plants, poles, and wires are of critical importance, but regulatory and financial dynamics determine when, where, and how they are built. As our electricity grid undergoes transformative changes in the 21st century, from an influx of digital information to the paradigm-shifting impacts of climate change, regulatory institutions will play a role in what changes are made and how quickly they unfold. These regulatory-economic agreements affect the grid at every scale—from the way regions will grow and change, to individual decisions utilities and their regulators make every day. The following section highlights a

[21] Cohn, J. (2019, January). When the Grid Was the Grid: The History of North America's Brief Coast-to-Coast Interconnected Machine. Proceedings of the IEEE. Retrieved at: https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=8594689.

[22] National Academy of Engineering. Greatest Engineering Achievements of the 20th Century. Retrieved at: http://www.greatachievements.org/.

few terms and concepts that are useful for understanding the incentives and dynamics at play in current resource planning conversations in the Southeast.

### i. Electric Utilities, the Regulatory Compact, and the Integrated Resource Plan

The business of making electricity is unique from other parts of the modern economy in two ways. The first is that universal provision of safe, reliable electricity forms the backbone of the modern economy—making it a "public utility."[23] The second is that high barriers to entry and economies of scale have historically rendered the electricity industry a "natural monopoly," although this is changing as distributed energy resources become more widespread.[24] Given that accessible and affordable electricity is in the public interest and, as monopolies, utilities generally do not compete for customers, utility business practices require special attention from the public to ensure that utilities make decisions and set prices in the public interest. Public-sector regulators at public utilities commissions across the country work with utilities to ensure they are managed prudently and in the public interest in what is often called a "regulated monopoly."[25] Regulators use a variety of standards to ensure electricity service is in the public interest; a few include a standard of universal access and an expectation that service and prices be "just and reasonable."[26] If utilities can meet this standard, regulators generally allow the company to receive a reasonable rate of profit on electricity sales. This agreement, wherein utility companies agree to be regulated in the public interest in return for a reasonable opportunity to achieve a return on investment, is called the "regulatory compact."[27] The

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[23] Bonbright, James (1961). Principles of Public Utilities Rates. Columbia University Press. P. 2. Retrieved at: http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

[24] Corneli, S. & Kihm, S. (2015, November). Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future. Lawrence Berkeley National. Laboratory. Retrieved at: https://emp.lbl.gov/publications/electric-industry-structure-and.

[25] Bonbright, p. 22.

[26] Federal Energy Regulatory Commission (2020, July). An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities. Retrieved at: https://www.ferc.gov/sites/default/files/2020-07/ferc101.pdf.

[27] Lazar, J., (2016, June). Electricity Regulation in the US: A Guide. Regulatory Assistance Project. Retrieved at: https://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf. P. 6. Lazar notes

compact places pursuit of the public interest at the center of the electric utility business model: a chance at a reasonable rate of profit is dependent on the utility's ability to pursue the public good.

While the general outlines of the regulatory compact are similar across the country, regulation of electric utilities occurs at the state level. States each appoint or elect a commission of public officials (called a public utilities commission or a public service commission) to regulate utilities in their jurisdiction.

Physically, the operation of the electric grid can be divided into distinct segments: ***generation*** describes where and how electrical energy is generated; ***transmission*** describes how electrical energy is transported from where it is created to where it is needed; and ***distribution*** describes how energy is brought to an appropriate voltage and distributed to customers. The purpose of each segment is distinct, but they need to operate in careful synchronization to meet the needs of electricity customers.

For much of the 20th century, electric utilities were 'vertically integrated': the same entities owned and operated all three segments of the grid. Cost overruns and shocks to energy prices during the 1980s, however, challenged the regulatory compact and the vertically integrated model. The existing arrangement did not seem to ensure that customers were protected from price shocks in the long run, and long-held assumptions about economies of scale, fuel costs, and growth in demand were shaken.

New policies and structures were proposed to ensure that utilities were taking prudent steps to ensure affordable electricity in the future. In particular, states instituted requirements for transparency and an opportunity for regulators to weigh in on utilities' long-term plans. Most states formally require utilities to submit an ***integrated resource plan***, which lays out utilities' plans for providing sustainable, low-cost energy over the long term.

A map of states that have instituted integrated resource planning requirements is provided in Figure A-1.

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that the regulatory compact is not a discrete contract or document that represents the regulatory compact, but that it is an "implied agreement."

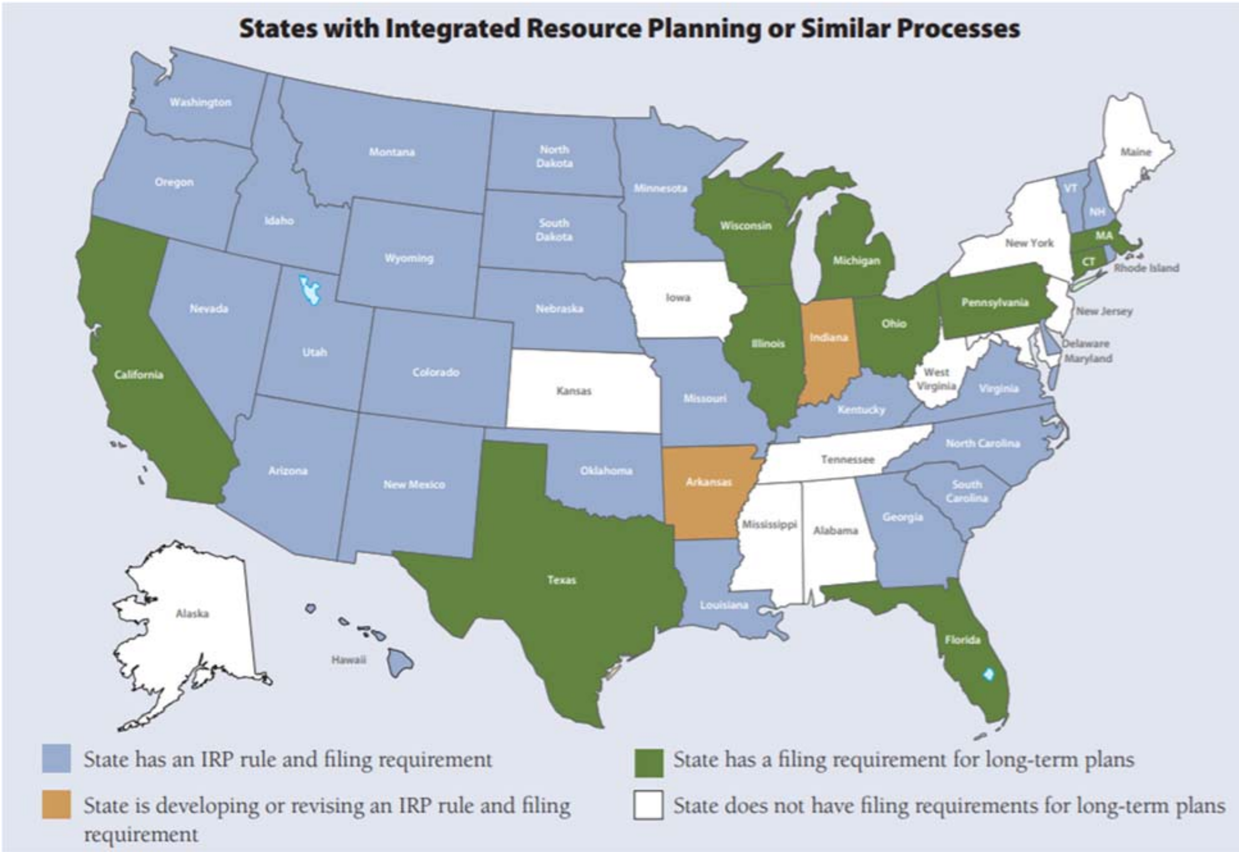


***Figure A-1.*** *States with Integrated Resource Planning or Similar Processes.*[28]

IRPs include projections for future energy needs, an inventory of resources currently available, and plans to construct new power plants to meet anticipated needs. Regulators typically have an opportunity to review and approve, reject, or revise these plans before they are put into effect. A transparent and robust integrated resource planning process between utilities, regulators and advocates ensures not only that current utility practices are in the public interest, but that the utility is prudently laying the groundwork to continue to provide sustainable, affordable power for decades to come.

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[28] Wilson, R., & Biewald, B. (2013, June). Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project and Synapse Energy Economics. Retrieved at: https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf.

### ii. Accounting for Generation Investments: Revenue Requirement and Depreciation

The regulatory compact ensures that as long as utilities are acting in the public interest, they are allowed to charge customers for the cost of service, plus an opportunity to receive a fair rate of return on their investments. Of course, provision of electric power is only in the public interest to the extent that it is affordable. This section describes how the investments envisioned in the integrated resource plan are eventually incorporated into everyday utility prices. Several concepts from utility cost accounting are introduced below, including the revenue requirement, rate base, and depreciation.

The first step in determining the appropriate amount to charge customers is determining the total cost of providing electricity over the course of a given year. This annual sum is called the ***revenue requirement*** because it represents the amount of revenue the utility needs to take in in order to pay off all its costs. The revenue requirement includes all costs incurred by utility, from executive compensation to fuel costs and income taxes. The total amount of the revenue requirement is the fundamental driver of the price of electricity, as shown in the equation below.

$$\frac{Revenue\ requirement\ (\$)}{Total\ electricity\ sold\ (kilowatt-hours)} = Average\ price\ of\ electricity\ (\$/kilowatt-hour)$$

***Equation A-1.*** *Relationship of revenue requirement to average price of electricity.*

The revenue requirement must also account for the actual equipment that the utility invests in that make up the physical grid, from power plants to distribution poles. In accounting terms, these pieces of equipment are called ***assets*** and the total value of these investments is called the utility's ***rate base***. A utility's assets add to the revenue requirement in two ways. First, in keeping with the regulatory compact, the utility is allowed an opportunity to earn a profit off of its investments. A set profit margin from the utility's investment in grid equipment, called a return on investment, is included in the revenue requirement (importantly, this means that a utility's profit margin is directly related to the size of its rate base). Second, the revenue requirement also includes the costs of wear and tear on the utility's equipment and assets as they operate over the course of the year. This wear and tear is called

***depreciation*** on the utility's accounting statements. It is represented as a cost to the utility as the value of its assets decreases due to wear and tear.

By accounting for depreciation, utilities ensure they have the funds they need to rebuild new assets as others wear away. An example might be helpful here. A hypothetical transformer has an expected operating lifetime of fifty years, which means after fifty years of operation it will need to be replaced with a brand-new transformer to continue safe and reliable service. In order to raise the money to replace the transformer in fifty years, the utility needs to increase the total amount it charges customers every year (the 'revenue requirement') by a small amount, to build funds to replace the transformer. After fifty years of wear and tear and depreciation costs, the transformer is ready for retirement and the utility has accumulated enough revenue over the years to purchase and install a replacement.

Utilities record return and depreciation for all assets they own, from distribution transformers to transmission lines and large power plants. As a result, depreciation represents a substantial part of the total revenue requirement. When Duke Energy's operating companies in the Carolinas submitted a proposal to increase electricity rates in North Carolina last year, the companies' estimated depreciation costs totaled $2.3 billion in 2018, or 22 percent of the utilities' overall expenses. It is the fourth largest category of costs, after fuel costs, operations & maintenance, and the utility's profit margin. Depreciation costs are also as long-lived as the assets they track—up to half a century or more, depending on the piece of equipment. As a result, it is of critical importance to regulators, utility management, and ratepayers that utilities exercise caution and prudent judgment when considering investment in new, capital-intensive power generation.

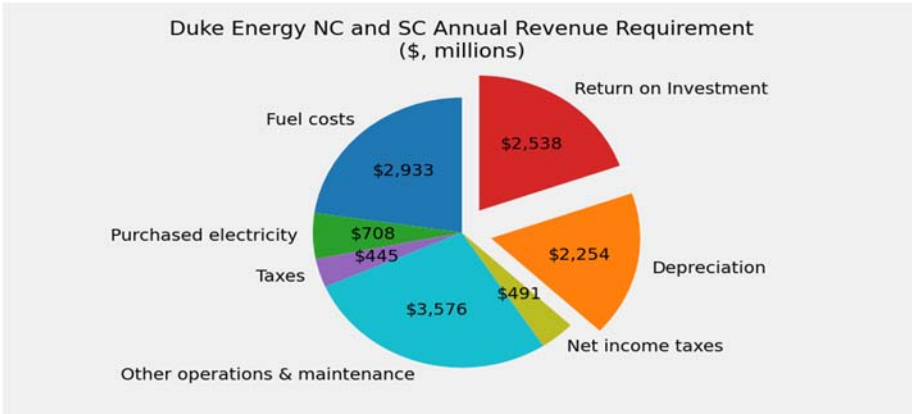


***Figure A-2****. Duke Energy Revenue Accounting for Duke Energy Carolinas and Duke Energy Progress in 2018*[29]

### iii. Investments in the Public Interest: The 'Used and Useful' Standard and Stranded Asset Risk

To fulfill their end of the regulatory compact, regulators carefully review the revenue requirement, and the depreciating investments included, to determine if it is in the public interest. These regulators must strike a careful balance: If the revenue requirement is too low, utilities might not be able to recover enough revenue to replace key equipment and pay off debts. But because investor-owned utilities have an obligation to shareholders and the return on investment is dependent on how much utilities invest in grid equipment, utilities also have a bias toward investing in new equipment and therefore increasing their revenue requirement.[30] To ensure the revenue requirement is just and reasonable, regulators need to assess which investments are made in the public interest and which are not. This section describes the toolkit available to regulators to ensure investments are in the public interest and explores how that toolkit is used in practice.

[29] Duke Energy Carolinas, LLC (2019, October). Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. NCUC Docket No: E-7, Sub 1214. P. 238. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=d9326636-e0f5-481e-8691-ce4362fd96d2.; *and*
Duke Energy Progress, LLC (2019, October). Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets. NCUC Docket No: E-2, Sub 1219. P. 279. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=e84103e3-d5a6-4526-9b27-76fcee8764c8.

[30] Shipley, J., (2018, January). Traditional Economic Regulation of Electric Utilities. Regulatory Assistance Project. Retrieved at: https://www.raponline.org/wp-content/uploads/2018/12/rap_shipley_pucs_regulation_overview_2018_dec_17.pdf.

To ensure only investments in the public interest are included in the rate base and revenue requirement, regulators employ a two-part test. In order to receive profit for any asset that a utility invests funds into, the utility must demonstrate that a) the asset is actually being used during the grid's operation; and b) that the asset's use was necessary for prudent grid operations. This test is referred to as the ***used and useful standard.***[31] Assets can fail to qualify as 'used and useful' for several reasons. The clearest example is that of a piece of equipment that is purchased or constructed but is never actually put into operation. Increasingly, legacy fossil-fueled assets are facing risks of losing their used and useful status simply because low-cost renewables can provide the same service at a lower cost.[32] Even if a piece of equipment passes the used and useful standard immediately after it was built, it must continually be used and useful to stay in the rate base and contribute to the utility's revenue requirement.

When assets fail to meet the used and useful standard, their depreciation costs and return on investment are removed from the revenue requirement and the utility's total revenues decrease. In order for depreciation costs and returns to be reintroduced to the revenue requirement, the utility must demonstrate that the asset has returned to 'used and useful' status. When assets have no plausible pathway toward becoming used and useful, they may not result in any additional revenue for the utility and thus create a shortfall: The utility has invested funds in an asset, but has no way to derive revenue from it. In financial terms, these investments are called ***stranded assets***.[33]

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[31] Bilich, A., Colvin, M., & O'Connor, T., (2020). Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California. Environmental Defense Fund. P. 11. Retrieved at: https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

[32] *See* Gimon, E., O'Boyle, M., Clack, C., & McKee, S., (2019, March). The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. *Energy Innovation*. Retrieved at: https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf; *or* Teplin, C., Dyson, S., Engel, A,. Glazer, G., (2019). The Growing Market for Clean Energy Portfolios. *Rocky Mountain Institute.* Retrieved at: https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/.

[33] Sen, S. (2020, March). Climate policy, stranded assets, and investors' expectations. *Journal of Environmental Economics and Management.* Retrieved at: https://www.sciencedirect.com/science/article/pii/S0095069618307083.

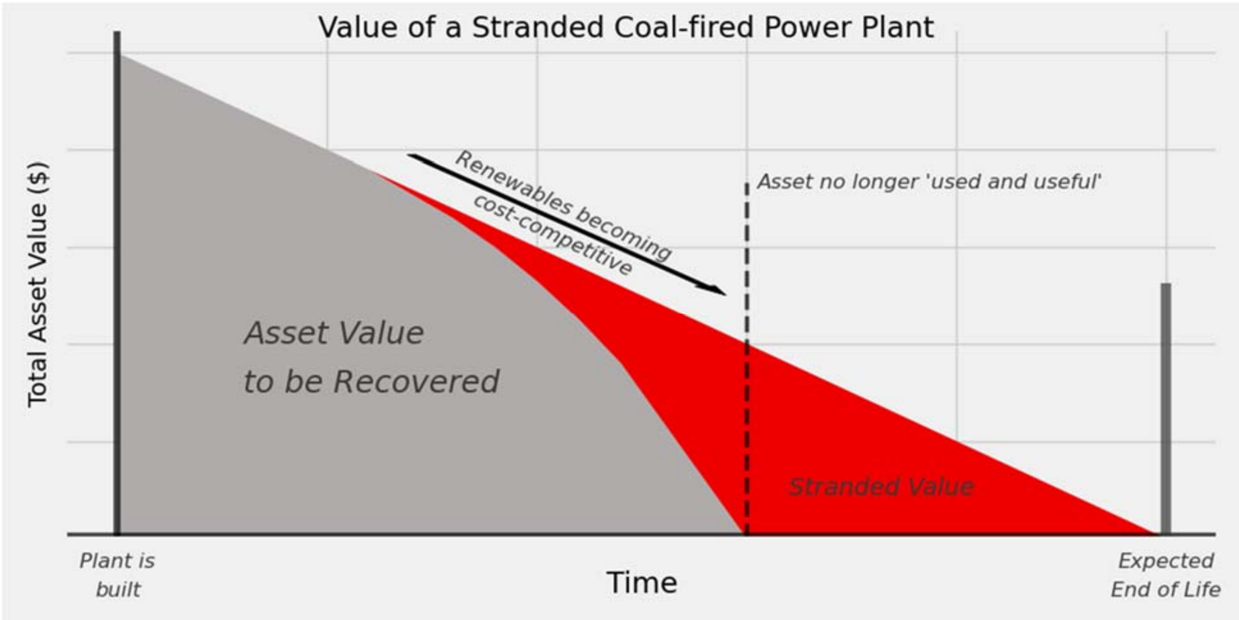


***Figure A-3.*** *Diagram of stranded value of a hypothetical coal-fired power plant*[34]

The diagram above represents a hypothetical coal-fired power plant that is facing pressure from low-cost renewable generation. When it was built, the power plant was expected to maintain its used and useful status for several decades, far into the 21st century. However, as carbon constraints changed the project's economics and renewables plus storage become more cost-competitive, the utility chooses to run the coal plant less frequently because less expensive options are available. Eventually, the coal plant ceases to be used for power generation at all because of complete substitution by more cost-competitive options, thereby failing the 'used and useful' standard. To demonstrate this phenomenon, the coal asset value over time is plotted in Figure A-3. The y-axis represents the total asset value of the plant, and the x-axis represents the passage of time. Over time, the asset's value decreases due to depreciation. But as utilities generate electricity from more economic options, the coal plant becomes less and less 'useful.' When the coal plant is no longer used to generate electricity, it fails to meet the used and useful standard. The area shaded in red, representing expected value from the asset that is never realized, is the 'stranded' value.

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[34] *Image inspired by:* Bilich, A, *et al.*, p. 17.

Theoretically, the 'used and useful' standard is a powerful tool for regulators to ensure that utilities operate efficiently and ratepayer costs remain low. In practice, however, the standard is difficult to implement. Regulators operate with less information at their disposal than utility companies,[35] and, as described above, utilities are incentivized to include as much capital as possible in their rate base. As a result, utilities have historically enjoyed the presumption from regulators that their investments are used and useful, instead of a strict burden of proof.[36]

In some cases, the relative hurdle for utilities to prove the used and useful nature of their assets has shifted even further. Utilities have (often successfully) argued that even if a given asset ceases to be used and useful, the utility should be able to continue to receive payment because it *appeared* to be a prudent investment at the time it was built. Although this was not the original intention of the standard, the effectiveness of the used and useful test has been substantially diminished by overriding concerns about the financial health of the utility.[37]

Utility executives and financial observers have adapted to the weakened implementation of this standard. In a 2018 report on stranded asset recovery, Moody's Investor Service found that "In almost all cases, the utilities were able to recover stranded costs without hurting their credit quality."[38] Another survey of investors in the power generation sector found that investors "take stranded asset risk into consideration, but that they also expect a financial compensation for their stranded assets."[39] In this environment, utilities might be emboldened to make risky, carbon-intensive capital investments, given a higher level of confidence that they will avoid penalties if the asset ceases to be

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[35] Ozar, R., (2017, November). Incentive Regulation of Distribution Utilities, A Primer: Theory and Practice. Retrieved at: https://www.michigan.gov/documents/mpsc/Appendix_H_609239_7.pdf.

[36] Lazar, p. 52.

[37] Hoecker, J. (1987). "Used and Useful" : Autopsy of a Ratemaking Policy. Retrieved at: https://www.eba-net.org/assets/1/6/25_8EnergyLJ303(1987).pdf.

[38] T&D World, (2018, November). "Stranded Asset Risk is Low for U.S.-Regulated Utilities as They Shift To Renewable Energy." Retrieved at: https://www.tdworld.com/grid-innovations/generation-and-renewables/article/20971907/stranded-asset-risk-is-low-for-usregulated-utilities-as-they-shift-to-renewable-energy.

[39] Sen.

used and useful. As the electricity grid undergoes a transformation in the 21st century, utility executives are maintaining their confidence in asset recovery; less than twenty percent of utility executives believe that stranded generation assets are a major risk through the energy transition.[40] The potential consequence of this stance toward stranded assets is that utilities may charge their ratepayers for investments and equipment that are not providing value to the system, even when such risks are foreseeable. While there is more certainty for utility executives and shareholders, ratepayers bear the burden of stranded asset costs.

The evolution of the used and useful standard represents a gap in public oversight and a shift of risk from utilities to ratepayers. If a utility makes investments that do not ultimately prove useful, are hindered by long-anticipated regulation, or are outcompeted by new technologies, utility ownership would bear the costs under the traditional used and useful standard. Under the commonly practiced implementation of the standard, though, utilities could still earn a return on those investments, creating an obligation for ratepayers to pay off those investments. In the context of modern integrated resource planning, where utilities are investing in long-lived technologies in a rapidly changing economic, regulatory, and technological environment, ratepayers face substantial exposure to paying off assets that are ultimately not useful, while utilities shareholders are insulated.

## B. Climate Risk's Disruptive Impact on Utility Planning

Institutions like the regulatory compact, the used and useful standard, and cost-of-service ratemaking have guided the electricity industry since the 1800s, but the regulatory system will face new challenges in the 21st century. The onset of climate change is applying new shocks and stresses to legacy utility assets—a phenomenon most clearly seen in the wildfires started by utility equipment (and eventually

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[40] Morehouse, C., (2020, February). "Utilities don't see stranded assets as a top risk. Should they?" *Utility Dive*. Retrieved at: https://www.utilitydive.com/news/utilities-dont-see-stranded-assets-as-a-top-risk-should-they/572246/.

bankrupting Pacific Gas & Electric) in California's 2018 wildfire season.[41] It has also galvanized a market, social, regulatory and economic response that is transforming the industry. Renewable energy resources, like solar and wind energy, have become a least-cost power resource and are displacing legacy fossil generation across the country.[42] Energy storage, long assumed to be too expensive to be deployed at scale, is appearing *en masse* across the grid.[43] Local and state policymakers have increased their ambition again and again with legislative and executive actions guiding the country toward a decarbonized power system.[44] At the same time, these actions are unfolding while the grid is becoming increasingly digital and more information is available than ever.[45] As utilities and their regulators plan for the future, they must do so while the ground is quickly shifting underneath their feet, using tools that were designed in a different era.

Beyond electricity, climate risks and opportunities are transforming the whole economic landscape, and central institutions are responding. Economic and financial leaders from the Federal Reserve, G20's Financial Stability Board, and BlackRock CEO Larry Fink are preparing for transformative shifts across the economy. The need for a common language on climate impacts led the G20's Financial Stability Board to create the Task Force on Climate-Related Financial Disclosures (TCFD). The TCFD's standards and recommendations, adopted by over 800 organizations representing over $118 trillion in

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[41] MacWilliams, J., La Monaca, S., & Kobus, J., (2019, August). PG&E: Market and Policy Perspectives on the First Climate Change Bankruptcy. Columbia Global Energy Program. Retrieved at: https://energypolicy.columbia.edu/sites/default/files/file-uploads/PG&E-CGEP_Report_081519-2.pdf.

[42] Teplin *et al.*

[43] Wood Mackenzie, (2020, December). U.S. Energy Storage Monitor. Retrieved at: https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/.

[44] Micek, K., (2020, August). Analysis: States' renewable mandates continue to grow; nine set 100% clean energy goals. S&P Global. Retrieved at: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081420-states-renewable-mandates-continue-to-grow-nine-set-100-clean-energy-goals.

[45] St. John, Jeff., (2020, August). 5 Grid Edge Mega Trends in 2020. *GreenTechMedia.* Retrieved at: https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/5-grid-edge-mega-trends-in-2020.

assets, have become the international standard for discussing the financial and economic impacts of climate change.[46]

Key to the TCFD's definition of climate risk is an acknowledgement that the risks and opportunities arising from climate change originate not just in the change in physical phenomena, but also the collective societal and economic response to mitigate and adapt to climate change. The TCFD calls the risks and opportunities caused by the social & economic response to climate change 'transition risks' and categorizes them into financial, regulatory, economic, and reputational risks. Understanding those risks as separate from but linked to the physical risks is necessary for a complete view of the financial and economic impacts of climate change.

The utility sector's expensive, long-lived and immobile assets, combined with its historical reliance on fossil fuels and attendant greenhouse gas emissions, create a special sensitivity to these risks.[47] Utilities will need to anticipate and adapt to these risks and opportunities, and traditional regulation and planning concepts will need to adjust to reflect this reality and continue to serve the public interest.[48]

Duke Energy and its companies in the Carolinas are on the leading edge of these climate transformations. As a state in the Sun Belt, North Carolina has a solid solar resource and is second only to California in total deployment of solar energy.[49] At the same time, the state is grappling with its increased vulnerability to climate-related risks like amplified hurricanes and sea level rise. Those factors led Governor Roy Cooper to sign Executive Order 80 in 2018, which is paving a path for a climate-

[46] Task Force on Climate-Related Financial Disclosures ("TCFD") (2019, June). Task Force on Climate-related Financial Disclosures: Status Report. Retrieved at: https://assets.bbhub.io/company/sites/60/2020/10/2019-TCFD-Status-Report-FINAL-0531191.pdf.

[47] TCFD.

[48] Gimon, E., (2020, April). Why Climate Advocates Should be Interested in Resource Adequacy. Energy Innovation. Retrieved at: https://energyinnovation.org/wp-content/uploads/2020/04/Why-Climate-Advocates-Should-Be-Interested-In-Resource-Adequacy.pdf.

[49] Solar Energy Industries Association (2020). North Carolina Solar. Retrieved at: https://www.seia.org/state-solar-policy/north-carolina-solar.

resilient state.[50] Duke Energy will need to play a major part in the transition in the Carolinas; it covers the lion's share of retail electricity in North and South Carolina, and its nationwide footprint of utility companies represents the highest total greenhouse gas emissions among power producers in the country.[51] Duke Energy's footprint in the Carolinas therefore represents a fitting case study for understanding the emerging risks and opportunities from climate change. Each of the risk categories identified by the TCFD is presented below, with a brief description of risk exposure to Duke's portfolio in the Carolinas and implications for utility planning in the future.

### i. Physical Risks: Assets at risk of damage from climate-fueled exposure

Physical risks describe the ways that climate-related physical phenomena, like rising sea levels, more intense storms, heat waves, or more frequent flooding could impair grid operations and damage or otherwise devalue utility assets. Understanding the risks to the economy in the Carolinas broadly, the North Carolina Department of Environmental Quality commissioned a Climate Science Report to understand the incidence of climate-related phenomena. The report found that "it is ***very likely*** that extreme precipitation frequency and intensity in North Carolina will increase," and "heavy precipitation accompanying hurricanes that pass near or over North Carolina is ***very likely*** to increase" [emphasis original].[52] Utility-specific analysis has also found a relatively high level of risk in the Carolinas. A report commissioned by Moody's analytics and authored by leading climate analytics firm Four Twenty Seven found that Duke is among the most at-risk utilities due to the changing climate, specifically pointing out hurricane threats.[53]

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[50] State of North Carolina (2018, October). Executive Order No. 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy. Retrieved at: https://files.nc.gov/governor/documents/files/EO80-%20NC%27s%20Commitment%20to%20Address%20Climate%20Change%20%26%20Transition%20to%20a%20Clean%20Energy%20Economy.pdf.

[51] Ceres (2020, May). Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States. Retrieved at: https://www.ceres.org/sites/default/files/reports/2020-07/Air%20Emissions%20Benchmark%202020.pdf.

[52] Kunkel *et al.*

[53] Morehouse.

To address a changing physical environment, utility planners and regulators will need to suspend an assumption that historical average environmental conditions are an appropriate approximation of present and future conditions. When Con Edison conducted a comprehensive study of climate impacts on the assets and operations of its system, the utility found its "systems are all vulnerable to increased flooding and coastal storms; … [and] increasing temperatures; and the electric system is also vulnerable to heat events."[54] While ConEd's study focused on distribution systems, the same dynamics also apply to generation planning, from identifying concerns to engineering design standards.

### ii. Financial Risks: Growing interest in Environmental, Social, & Governance (ESG) Issues

Financial institutions have been on the leading edge of calling for more analysis of the economic risks of climate change, and financial actors are now beginning to act on that analysis and entities' mitigation plans. BlackRock, the third-largest shareholder in Duke Energy stock, is leading a reassessment of climate risks among financers. BlackRock CEO sent a letter to CEOs in January 2020 stating that climate change was driving a "fundamental reshaping of finance."[55] Over 2019 and 2020, BlackRock voted against boards of directors 55 times due to lack of progress on mitigating climate impacts.[56] The United States Commodity Futures Trading Commission released a report and recommendations on climate risk to the US financial system in September 2020, and one Commissioner concluded that managing climate risk "isn't someone else's job.'[57] Electric utilities like Duke will need to adequately characterize their level of climate risk, and prudently move to mitigate that risk, in order to maintain their level of financial health. Duke Energy's companies mention in

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[54] Con Edison (2019, December). Climate Change Vulnerability Study. Retrieved at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf?la=en.

[55] Fink.

[56] Partridge.

[57] Ellfeldt, A., (2020, September). "Regulator: Climate risk isn't 'someone else's job.'" *E&E News ClimateWire.* Retrieved at: https://www.eenews.net/climatewire/2020/09/21/stories/1063714225.

their most recent Carolinas IRPs that they are also facing interest from investors focused on environmental, social, and governance (ESG) issues.[58]

The standard for integrated resource planning is typically a 'least-cost' approach, where utility planners and regulators optimize to meet necessary demand for power at least cost to consumers.[59] The advent of climate-related risks and financial oversight complicates this standard. A given resource plan that results in least-cost short term, for example, may lead to higher financing costs over the long term because of its treatment of climate risks. Utility planners and regulators should be aware of this dynamic when deciding which resource plan is truly cost-optimal.

### iii. Economic Risks: Pressure from Low-cost Renewables

Renewable energy technologies, bolstered by supportive policy and early adoption by jurisdictions with ambitious climate policy, have become economically competitive with conventional generation, even on a no-subsidy basis.[60] These new resources, with zero ongoing costs for fuel, are already transforming the energy mix across the country. These conditions led competitive energy supplier Vistra to announce that it would retire 6,800 megawatts of coal capacity in the Midwest by 2027.[61] When experts from the Rocky Mountain Institute assessed the cost of replacing gas generation, hour-for-hour, with zero-carbon energy resources, they found that 90 percent of new proposed gas plants could be cost-effectively substituted with clean energy resources—and that by the mid-2020s, even existing gas plants could be outcompeted by new-build clean energy resources.[62] Analysis from Bloomberg New Energy Finance found the same result, noting that hybrid solar-plus-storage assets

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[58] DEC IRP Report, p. 93.

[59] This standard is often directly written into statutes regarding Integrated Resource Plans; See N.C. G. S. § 62-2(3a);

[60] Lazard.

[61] Morehouse, C., (2020, September). "Vistra to retire 6.8 GW coal, blaming 'irreparably dysfunctional MISO market.'" *UtilityDive*. Retrieved at: https://www.utilitydive.com/news/vistra-retire-68-gw-coal-blames-irreparably-dysfunctional-miso-market/586113/.

[62] Teplin *et al*.

"represent a zero-emissions threat to gas," and "undermine the case for many proposed new-build gas power plants, and dramatically change the generation profiles and economics of others."[63]

Experts and analysis are finding the same result in the Southeast. Analysts at Vibrant Clean Energy have found that all coal plants in the Carolinas would be outcompeted by wind and solar by 2025,[64] and a study sponsored by the University of California at Berkeley shows that the Carolinas could get to 90 percent clean energy by 2035—without an overall increase in energy prices.[65] If utilities in the Southeast pooled their resources across utility lines, they could integrate far more renewable resources—at a lower cost to ratepayers.[66]

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[63] BloombergNEF, (2020, November). How PV-Plus-Storage Will Compete With Gas Generation in the US. Retrieved at: https://assets.bbhub.io/professional/sites/24/BloombergNEF-How-PV-Plus-Storage-Will-Compete-With-Gas-Generation-in-the-U.S.-Nov-2020.pdf.

[64] Gimon, E., O'Boyle, M., McNair, T., Clack, C., Choukulkar, A., Cote, B., & McKee, S., (2020, August). Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market. *EnergyInnovation and Vibrant Clean Energy.* Retrieved at: https://energyinnovation.org/wp-content/uploads/2020/08/Economic-And-Clean-Energy-Benefits-Of-Establishing-A-Southeast-U.S.-Competitive-Wholesale-Electricity-Market_FINAL.pdf.

[65] Phadke, A., Paliwa, U., Abhyankar, N., McNair, T., Paulos, B., Wooley, D., O'Connell, R., (2020, June). 2035 Report: Plummeting Solar, Wind, and Battery Costs can Accelerate our Clean Electricity Future. Retrieved at: http://www.2035report.com/wp-content/uploads/2020/06/2035-Report.pdf?utm_referrer=https%3A%2F%2Fwww.2035report.com%2F.

[66] Gimon *et al.*

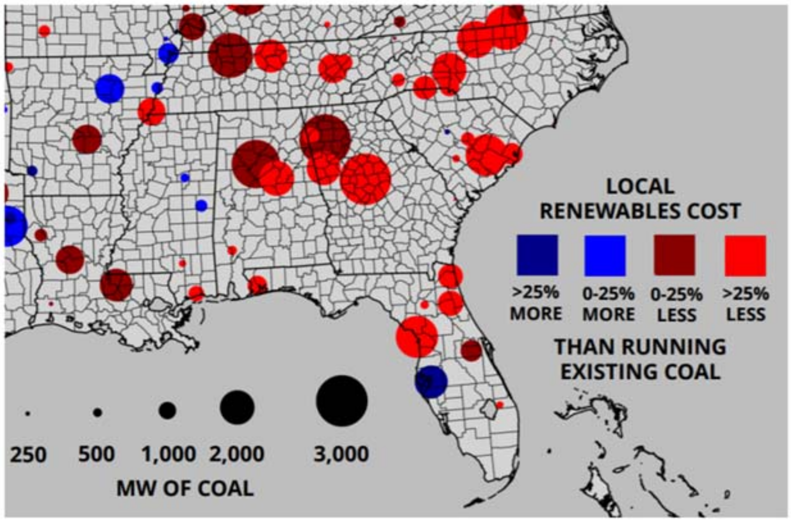


***Figure B-1.*** *Comparison of coal operating costs versus local renewables in the Southeast*[67]

For utilities and their ratepayers to take advantage of these economic opportunities and avoid the economic risks, generation planning processes must ensure that they are able to fully capture the value of variable and flexible resources. Traditional notions of cheap, inflexible 'baseload' resources versus more expensive 'peaker' resources do not apply cleanly to variable, low-cost resources like wind and solar or flexible, dispatchable resources like aggregated demand response or energy storage. To address this new reality, expert analysts have advocated for a more holistic view of generation capacity planning.[68] These dynamics contributed to the North Carolina Utilities Commission's request that Duke's companies not treat conventional reserve margin planning as a "hard and fast" rule:

> Prudent investments in additional generating capacity in the short term must take [risk of stranding from renewable resources] into account, and an absolute insistence on a single fixed and unvarying planning reserve margin does not … permit sufficient flexibility to do so.[69]

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[67] Gimon, E., O'Boyle, M., Clack, C., McKee, S,. (2019, March). The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. Vibrant Clean Energy and Energy Innovation. Retrieved at: https://energyinnovation.org/wp-content/uploads/2019/04/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL2.pdf.

[68] Gimon.

[69] North Carolina Utilities Commission ("NCUC"), (2020, April). Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans. Docket No. E-100, Sub 157. P. 11. Retrieved at: https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=86f15be3-7617-4910-aeae-d8568c4d0983.

### iv. Regulatory Risks: Carbon Prices & Clean Energy Standards

Regulatory climate-related risks in the utility sector represent risks to assets, net revenues, and operations by carbon or clean energy regulation at the state or federal level. Examples of policies that could cause regulatory costs include a price on carbon or a clean energy standard. In its most recent Carolinas IRPs, Duke Energy discusses several federal regulations that it has been tracking, including the Climate Leadership Council's proposal ($40/ton $CO_2$, escalating at 5 percent per year) and the American Opportunity Carbon Free Act of 2019 ($52/ton $CO_2$, escalating at 8.5 percent per year). To account for uncertainty and appropriate market signals, rather than a simple externality price, leading economists have also recently proposed risk-informed carbon prices that begin at a high value, then decline over time.[70]

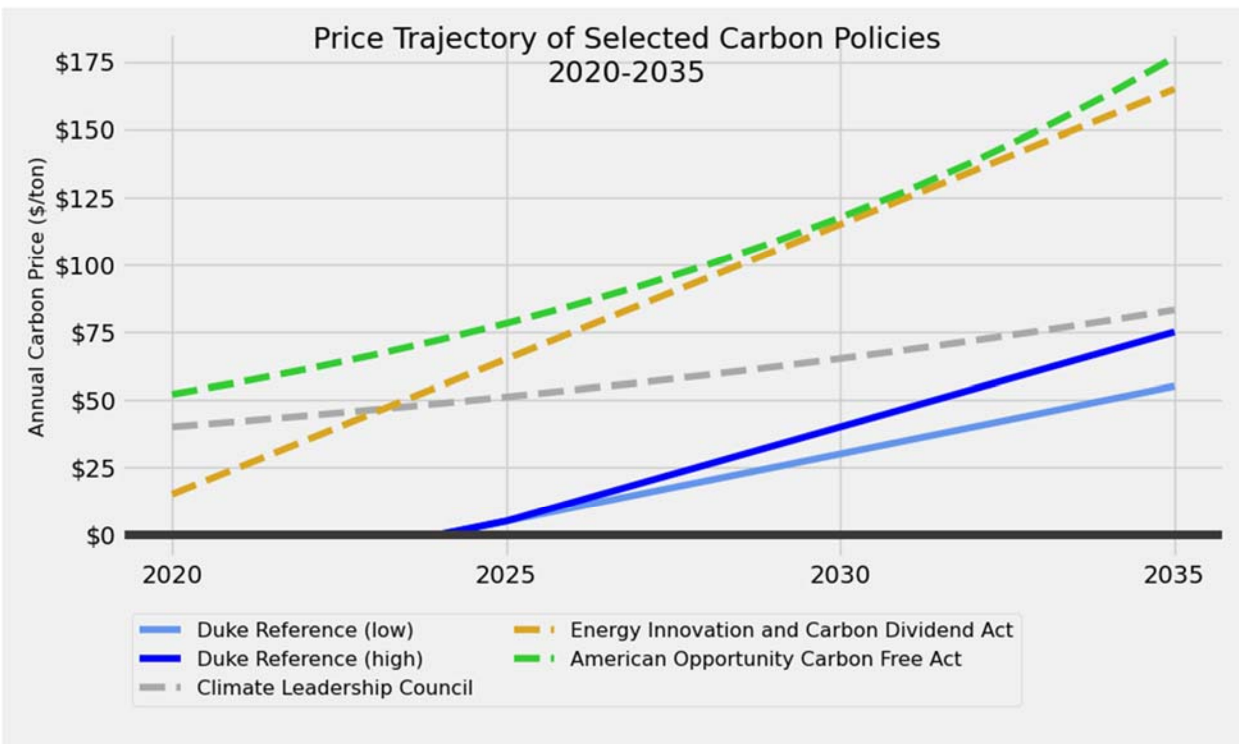


***Figure B-2.*** *Magnitude of potential federal carbon regulation prices, 2020-2035. Plotted with Duke Integrated Resources Plan reference carbon prices. Prices in nominal US dollars.*[71]

[70] For examples, see Gernot Wagner's EZ-Climate and Noah Kaufman's Near-Term to Net-Zero (NT2NZ).

[71] See DEC IRP Report, p. 152-154.



Exhibit TF-2

Incorporating a carbon price or clean energy standard is relatively straightforward in most resource planning processes, and Duke's most recent IRPs in the Carolinas have incorporated an assumed carbon price of $5/ton starting in 2025.

Ambition for state-level climate policy is also rising in the Carolinas. The Clean Energy Plan that emerged from Cooper's Executive Order 80 in 2018 contemplates several potential state-level policy actions,[72] and South Carolina's Energy Freedom Act of 2019 empowers the South Carolina Public Service Commission to consider a broader array of costs and risks when making its determination on whether an integrated resources plan is 'just and reasonable.'[73] The Clean Energy Plan and the Energy Freedom Act are further discussed in Section C.

### v. Reputational Risks: Do Utilities' plans line up with their net-zero commitments?

Reputational risks represent the risks to a firm's relationship with customers, regulators, suppliers, and the public due to the business's carbon emissions and its perceived progress on climate change mitigation and adaptation. Utilities that sustain reputational impacts due to their approach to climate risks may find less friendly relationships with regulators, political entities, and financial observers,which could ultimately have substantial effects on the utility's shareholders.

Utilities across the country have managed climate-related reputational risks by announcing commitments or goals to decarbonize their operations by 2050. The announcements could blunt regulators' inclinations to mandate decarbonization measures if there is a sense that utilities are good-faith actors who will decarbonize without the need for close regulation. A list of large utilities and their decarbonization targets is provided below.

[72] NC DEQ, 2019.

[73] Direct Testimony of Kenneth Sercy on behalf of the South Carolina Solar Business Alliance, Inc. (2020, July). South Carolina Public Service Commission Docket No. 2019-226-E. Retrieved at: https://dms.psc.sc.gov/Attachments/Matter/c6cfec80-c3eb-46f8-b9fd-26b9a76ee9ca.

***Table B-1.*** *Major Utility Carbon Emissions Goals, sorted by announcement date.*[74]

| **Company** | **Carbon Commitment** | **Date Announced** |
|---|---|---|
| FirstEnergy | 90 percent by 2045 | December 2015 |
| Xcel Energy | Net zero by 2050 | December 2018 |
| Dominion | Net zero by 2050 | December 2018 |
| NextEra Energy | 40 percent by 2025 | June 2019 |
| PSEG | 80 percent by 2046 | July 2019 |
| DTE Energy | Net zero by 2050 | September 2019 |
| AEP | 80 percent by 2050 | September 2019 |
| **Duke Energy** | **Net zero by 2050** | **September 2019** |
| Southern Company | Net zero by 2050 | May 2020 |
| Entergy | Net zero by 2050 | September 2020 |
| Ameren | Net zero by 2050 | September 2020 |

For utility executives, decarbonization goals could be a double-edged sword. As long as the public perceives that utilities are proactively implementing their climate commitments, decarbonization goals could be a reputational asset. If public perception were to find that utilities were not moving to achieve their carbon goals, then the decarbonization goal could be a liability for the company.

As the number of utilities with decarbonization goals has accumulated, public scrutiny has increased. A September 2020 report from Deloitte concludes that generally, "the math doesn't yet add up" when it comes to utility decarbonization plans.[75] Another report from Synapse found that "utilities appear in some cases to simply be responding to state pressures or requirements rather than demonstrating

[74] Gearino, D.

[75] Porter, et al.



Exhibit TF-2

the independent leadership needed to achieve ambitious decarbonization targets."[76] For utilities like Duke to avoid sustaining reputational damage, they need to ensure that public-facing planning presents a credible, good-faith attempt at decarbonization.

### vi. Revisiting Stranded Assets in Light of Climate Risks

Traditionally, utility planners and their regulators enjoyed the assumption of consistency. With the exception of total demand for electricity growing slowly year-to-year, utility planners were able to plan years and even decades into the future with a generally reasonable presumption that future conditions would be similar to the present. Climate change's impacts on the utility sector have obliterated that presumption. Utility planners now need to make their decisions in a context where climate-related risks continue to evolve at a rapid pace. There is no question that these risks will continue to develop and emerge: Utilities' common net-zero goal year, 2050, is less than three decades away. Energy infrastructure built today will be well within its operating lifetime through mid-century.

These quickly evolving risks multiply the potential risk for utility investments. Although the categories of climate-related risks have different vectors, each could contribute to a historical investment losing its used-and-useful status, years before expected. Of course, careful, climate-risk-informed planning could also avoid these stranded assets. The North Carolina Utilities Commission acknowledged this dynamic in its March 2020 order::

> The Commission observes that all parties agree that the near and intermediate term periods will be marked by rapid technological change accompanied and reinforced by potentially dramatic changes in the costs of new generating technologies and compounded by an increasing emphasis on reduction in greenhouse gas emissions from electric power generation. The Commission's view is no different. For this reason it is important when applying the principle of long-term least cost planning for generation assets that the Companies avoid near term investments in long-lived

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[76] Biewald, B., Glick, D., Hall, J., Odom, C., Roberto, C., & Wilson, R., (2020, March). Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets. Synapse Energy Economics. Retrieved at: https://www.synapse-energy.com/sites/default/files/Investing-in-Failure-20-005.pdf.

generating assets that may, due to market forces and technological change, become economically stranded over the course of the longer planning period.[77]

The US Commodity Futures Trading Commission (CFTC) puts the sentiment more simply: "In essence, transition risks arise when firms fail to prepare for or recognize broader market transitions. In a speedy transition to a net-zero economy, fossil fuel industry assets might become stranded."[78] The CFTC cites estimates of potential stranded asset cost due to climate-related transition risks up to $4 trillion across the economy. If firms and their financers fail to adequately consider transition risks, CFTC warns, systemic impacts are possible. Given the urgency of central economic actors' messages on climate risk, the transition to proactively managing climate risk is more a question of 'when' than a question of 'if.'

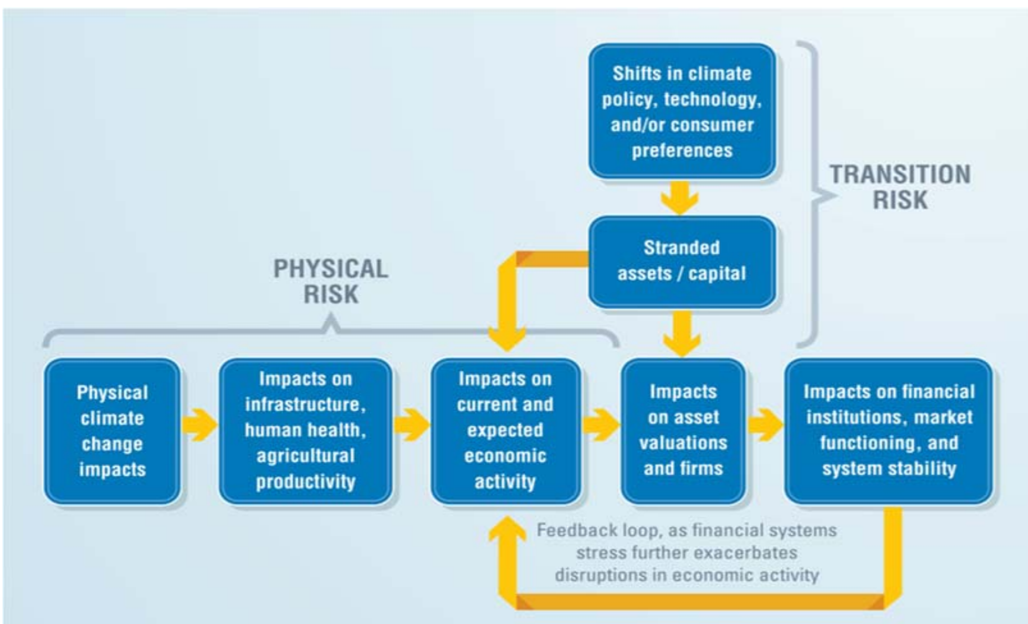


**Figure B-3.** *Impacts of physical and transition risks on assets, firms, and financial markets. From U.S. Commodity Futures Trading Commission, "Managing Climate Risk in the U.S. Financial System."*[79]

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[77] NCUC.

[78] U.S. Commodity Futures Trading Commission (2020, September). Managing Climate Risk in the U.S. Financial System. P. 19. Retrieved at: https://www.cftc.gov/sites/default/files/2020-09/9-9-20%20Report%20of%20the%20Subcommittee%20on%20Climate-Related%20Market%20Risk%20-%20Managing%20Climate%20Risk%20in%20the%20U.S.%20Financial%20System%20for%20posting.pdf p. 19.

[79] *Ibid.*

While each of the transition risks listed above might impact utility assets and operations through different vectors, they are each capable of impairing operations and causing stranded assets. To simplify the discussion of stranded assets and stranded asset costs due to climate-related transition risks, this concept will be called '***carbon stranding***' throughout this report.

## C. Duke's Portfolio and Integrated Resource Plan in the Carolinas

The remainder of this report will apply this understanding of resource planning, stranded assets, climate-related risks, and carbon stranding to Duke Energy's generation portfolio in the Carolinas, with a particular focus on the Duke Energy companies' 2020 Integrated Resource Plans, filed September 1, 2020 with the North Carolina Utilities Commission and the South Carolina Public Service Commission. The report will explore the companies' current portfolio of large power generators, then characterize the specific planned generation investments in the Integrated Resource Plans. Given that these integrated resource plans are Duke Energy's first in the Carolinas after its commitment to net zero carbon by 2050, the report will discuss the compatibility of Duke's preferred portfolio with its climate commitments and emerging climate-related opportunities and risks.

### i. Duke Energy Carolinas, Duke Energy Progress, and their Generation Portfolios

Duke Energy is one of the largest energy holding companies in the United States, owning regulated utility subsidiaries that operate in Indiana, Ohio, Kentucky, the Carolinas, and Florida. In addition to its regulated utility companies, Duke Energy also operates a Gas Utilities and Infrastructure unit as well as a competitive Renewables unit. As an aggregated corporation, Duke Energy generates more electricity than any other entity in the United States and emits over 100 million tons of carbon dioxide annually, second only to Vistra Energy in the United States.[80]

[80] Ceres.

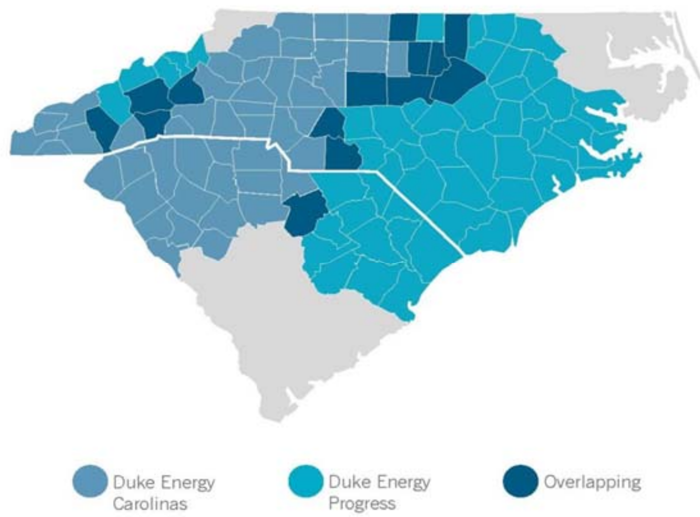


***Figure C-1.*** *Duke Energy Carolinas and Duke Energy Progress service areas.*[81]

In the Carolinas, Duke Energy owns two regulated utility companies, Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). Duke began operating both companies after a merger with Progress Energy in 2012. The companies are distinct corporate entities, but they coordinate power plant operations to serve load across the companies. They also submit coordinated regulatory proposals across companies, including Integrated Resource Plans. While the DEC and DEP IRPs are distinct, they will be treated as a single document throughout this report, and their generation portfolios will be treated as a single group. However, DEC and DEP fleets are still responsible for meeting resource adequacy standards over their respective footprints.

[81] The Hannon Law Firm (2020). Duke Energy Data Beach Exposed Personal Information of 370,000 Customers. Retrieved at: https://www.hannonlaw.com/blog/duke-energy-data-breach-exposed-personal-information-370000-customers/.

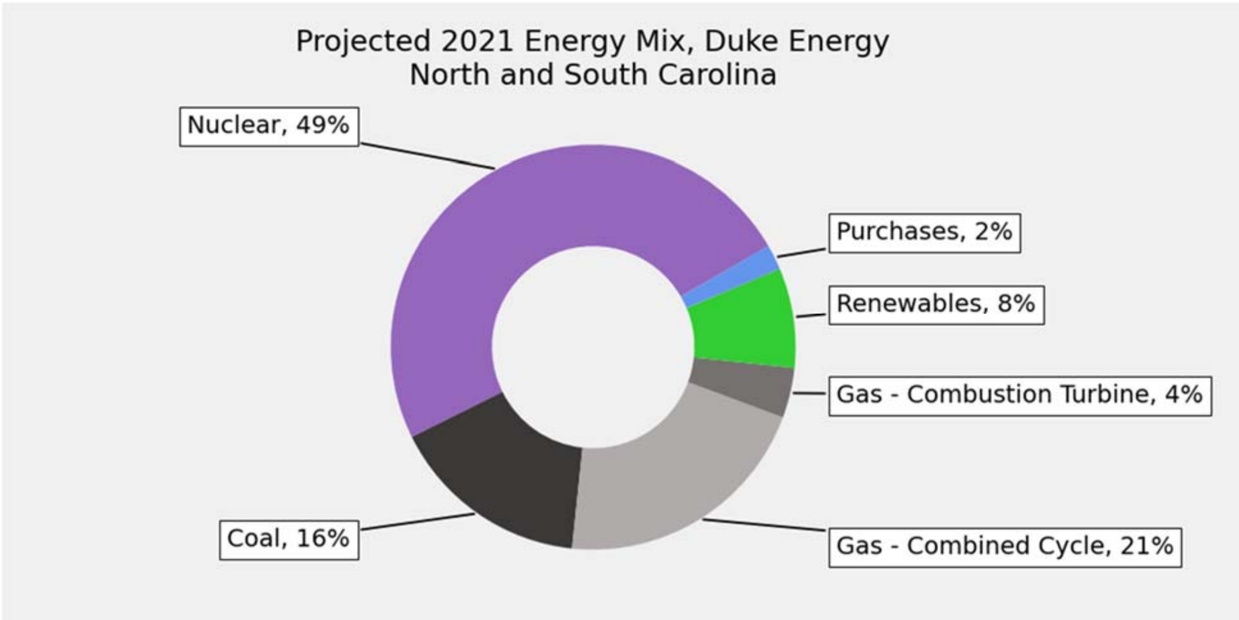


***Figure C-2.*** *Energy mix of Duke Energy Carolinas and Duke Energy Progress combined, projected for 2021.*[82] *Note that wind and solar, hydro, and energy efficiency are all included in 'renewables.'*

Duke Energy's projected energy mix for the Carolinas in 2021 is provided in Figure C-2. DEC and DEP rely on nuclear plants for just under half of all energy generation. Fossil-fueled resources, including coal-powered steam plants, gas-powered combined cycle plants, gas-powered combustion turbines, contribute another 40 percent. The remaining 10 percent is satisfied by renewables (mostly utility-scale photovoltaic solar), energy efficiency and demand-side management, and hydroelectricity, with two percent of energy imported from other utility systems. In recent years, DEC and DEP have pursued gradual retirement of their legacy coal fleet in favor of cheaper gas-powered generators. While Duke Energy's footprint in the Carolinas gets a zero-emissions boost from large nuclear fleet, the Duke utilities' fossil-fueled portfolio still represents one of the largest sources of carbon emissions in the Southeast.[83]

[82] DEC IRP Report, p. 107.

[83] Southern Alliance for Clean Energy (2019). Tracking Decarbonization in the Southeast 2019. Retrieved at: https://cleanenergy.org/wp-content/uploads/Decarbonization-in-the-Southeast-2020.pdf.

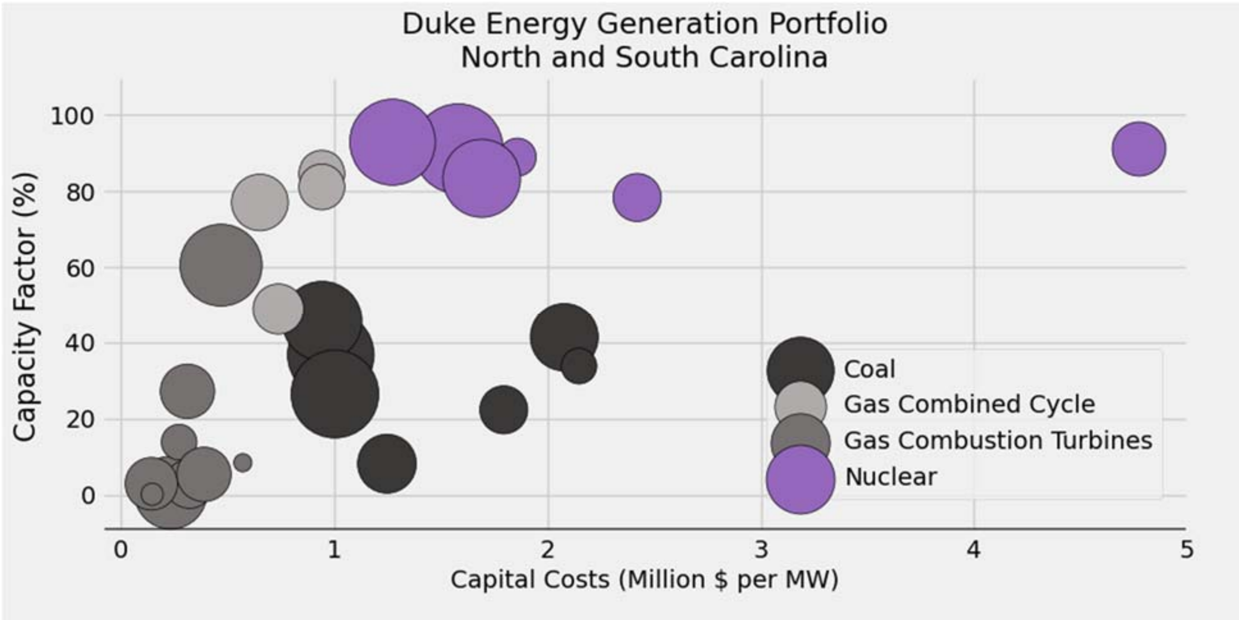


***Figure C-3.*** *Capacity Factor and Capital Costs of Duke Generating Units in the Carolinas.*[84]

Figure C-3 shows a simplified schematic of the large power generation plants owned and operated by Duke Energy in the Carolinas, as the companies reported to the Federal Energy Regulatory Commission in 2018. The x-axis shows the capital costs to build the plant, on a per-megawatt basis; plants further right on the x-axis are relatively more expensive, normalizing for size (the highest-cost outlier is the Shearon Harris Nuclear Power plant). The y-axis shows capacity factor, or how much the plant was in operation over the course of the year (in the case of this graph, 2018). Plants near the top of the y-axis were generating electricity at full capacity for almost every hour of the year; plants near the bottom of the y-axis only generated electricity for a few hours a year. Finally, the size of the dots on the graph represents the capacity of the unit, or the maximum amount of power it is able to generate at a time. The smallest unit in the fleet by capacity is Duke Energy Progress' oil-burning Blewett plant at 70 megawatts; the largest is Duke Energy Carolinas' Oconee nuclear plant at 2,666 megawatts.

Taken as a whole, the graph shows the types of large plants used to serve load in the Carolinas. The large, purple dots in the upper right of the graph's area represent the utility's nuclear fleet, which is relatively expensive and runs on an almost constant basis. Near the origin of the graph are the dark

[84] Data from FERC Form 1.

gray gas combustion turbines, which tend to be smaller and cheaper than the other options but operate for relatively few hours. Gas combined cycle plants represent a midpoint in cost and capacity factor between the nuclear fleet and the combustion turbines, and coal plants are generally larger and more expensive, but run less than half of the time.

### ii. Duke Energy's 2020 Integrated Resource Plans

As directed by regulatory authorities in North and South Carolina, Duke Energy Carolinas and Duke Energy Progress release an updated Integrated Resource Plan every two years, with an update published in the year between IRPs. Integrated Resource Plans include a 15-year planning horizon for new generation. In North Carolina, the North Carolina Utilities Commission does not explicitly approve or reject the IRP or any specific investment described within; instead, it determines whether the IRP is suitable for planning purposes. Then, when utilities seek permission to build new large generation units, they are approved or rejected roughly according to their inclusion in the most recent integrated resources plan.

*Context: Increasing momentum on carbon reduction*

Despite the short 2-year period between IRPs, the 2020 IRP for Duke Energy Progress and Duke Energy Carolinas sets an important precedent for the Carolinas' carbon emissions pathway. The following circumstances provide context for the 2020 IRPs.

**Duke's Net-Zero Carbon Commitment.**[85] In September 2019, Duke Energy committed to reaching net zero emissions across its corporate portfolio by 2050.[86] The announcement is a bold proclamation from one of the largest electric utilities in the country and a resounding signal that the transition to a zero-carbon energy system is underway. The 2020 Integrated Resource Plan represents Duke Energy's first long-term planning document in the Carolinas since the announcement of the net-zero carbon

[85] Duke Energy materials sometimes refer to their net-zero by 2050 aim as a 'goal,' and other times as a 'commitment.'

[86] Duke Energy (2019, September). Duke Energy Aims to Achieve Net Zero Carbon Emissions by 2050. Retrieved at: https://news.duke-energy.com/releases/duke-energy-aims-to-achieve-net-zero-carbon-emissions-by-2050.

commitment. As discussed in the previous section, climate commitments are a double-edged sword of reputational risk; they may preserve social license in the short term, but only if the company can show it intends to meet its goal. As stated in the 2020 IRPs, these plans represent a "road map" for Duke Energy to demonstrate follow-through on its commitment.[87]

**Cancellation of the Atlantic Coast Pipeline.** Duke Energy and Dominion Energy announced the cancellation of the Atlantic Coast Pipeline in July 2020.[88] The companies had already spent $3.4 billion on the project, and the pipeline's course was slated to extend for 600 miles, crossing the Appalachian Trail. In a release to press after the announcement of the cancellation, Duke Energy noted that while the pipeline was a "critical piece of Duke's decarbonization strategy," Duke would "continue advancing its ambitious clean energy goals by investing in renewables, battery storage, energy efficiency programs and grid projects" in the absence of the Atlantic Coast Pipeline.[89] The Atlantic Coast Pipeline could signal a shift for how utilities in the Southeast pursue decarbonization and securing energy resources, and Duke Energy's Integrated Resource Plans in the Carolinas provide a window into that shift.

**State Action.** Since the development of Duke Energy's previous integrated resource plans for the Carolinas, momentum has built around state action on climate risks and opportunities. North Carolina Governor Roy Cooper's Executive Order 80 created a framework for the state to assess its own vulnerabilities to climate change and envision a decarbonized energy system.[90] Since EO 80 was signed in 2018, state agencies and a broad group of stakeholders have worked to make the Order's programs concrete and implementation-ready. In October 2019, the North Carolina Department of Environmental Quality released a Clean Energy Plan in consultation with stakeholders across the state that targets a 70 percent reduction in greenhouse gas emissions from the power sector by 2030 and

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[87] DEC IRP, p. 8.

[88] Duke Energy (2020, July). Dominion Energy and Duke Energy cancel the Atlantic Coast Pipeline. Retrieved at: https://news.duke-energy.com/releases/dominion-energy-and-duke-energy-cancel-the-atlantic-coast-pipeline.

[89] Duke Energy (2020, July). The Road Ahead: An Update on the Atlantic Coast Pipeline. Retrieved at: https://www.myncma.org/download/public_documents/atlantic-coast-pipeline-FAQ-one-pager-FINAL-sm.pdf.

[90] State of North Carolina.

carbon neutrality by 2050.[91] In South Carolina, these plans represent Duke's first filed under the new Integrated Resource Plan requirements included in the Energy Freedom Act passed in 2019.[92] In May 2020, a consortium of universities in North Carolina released the North Carolina Climate Science Report, which projects large changes in the State's physical environment through the end of the century.[93] These reports are changing the understanding of climate risk and the public interest in the Carolinas, and Duke Energy has an opportunity to be responsive to these shifts in its integrated resource plan.

**Increased Commission attention.** As discussed in Section B of this report, state utilities commissions are not insulated from concerns over long-term climate risks and opportunities. In North Carolina, the North Carolina Utilities Commission has specified elements associated with climate risk that Duke Energy must address in its 2020 Integrated Resources Plan:

- Duke Energy should continue to model the impacts of potential carbon regulation on its plan;
- The Companies should remove any assumption that coal plants continue to operate uneconomically, and present portfolios that retire Duke Energy's coal fleet by the "earliest practicable date;"
- Duke Energy should further develop its previous illustrative scenarios for decarbonization by subjecting them to a more rigorous IRP process;
- Duke Energy should discuss the use of "all-source" procurement of energy resources, rather than choosing from conventional alternatives.[94]

Notably, the North Carolina Utilities Commission has been tracking some of these issues since Duke Energy's 2018 Integrated Resource Plans. In those proposals, the utilities sought approval for a buildout

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[91] NC DEQ.

[92] Robbins, S., & Mango, M., (2019, July). "Commentary: With Energy Freedom Act, South Carolina takes steps toward resilience." *Energy News Network.* Retrieved at: https://energynews.us/2019/07/25/southeast/commentary-with-energy-freedom-act-south-carolina-takes-steps-toward-resilience.

[93] Kunkel *et al.*

[94] DEC IRP Report, Table N-3.

of over 10 gigawatts of new gas-fired generation;[95] the NCUC ultimately did not accept the 2018 IRP for planning purposes beyond 2020 because it "[did] not accept some of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled."[96]

In South Carolina, Duke Energy's Plans are the first filed by Duke since the passage of the Energy Freedom Act, which substantially overhauled the IRP process in the state.[97] The Energy Freedom act directs utilities to present high-renewable scenarios as a part of its plan, and empowers the Commission to conduct a robust hearing to determine the prudency of utilities' long-term plans, considering factors including "commodity price risks" and other foreseeable conditions the Commission determines to be for the public interest. In December 2020, the South Carolina Public Service Commission found that Dominion Energy did not "properly assess risk and uncertainty" in its filed IRP, the first in the state under the new Act.[98]

In both states, Duke Energy's plans are subject to new attention on climate risks, and the tailwinds for climate-informed resource planning demonstrate the immediacy and magnitude of climate-related risks and opportunities.

### *Duke Energy's Filing*

Duke Energy Carolinas and Duke Energy Progress filed their Integrated Resource Plans with the NC and SC Commissions on September 1, 2020. Rather than proposing a single integrated resource plan as the recommended pathway, the filings instead include six scenarios according to requests from state

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[95] Walton, R., (2018, September). "Duke 15-year plans lean heavy on gas to replace coal." *UtilityDive.* Retrieved at: https://www.utilitydive.com/news/duke-15-year-plans-lean-heavy-on-gas-to-replace-coal/531924/.

[96] North Carolina Utilities Commission (2019, August). Order Accepting Integrated Resource Plans and REPS Compliance Plans, Scheduling Oral Argument, and Requiring Additional Analyses. Docket No. E-100, Sub 157. Retrieved at: https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=143d85de-b1e7-4622-b612-5a8c77e909d4.

[97] South Carolina Office of Regulatory Staff (2019, September). Summary of the South Carolina Energy Freedom Act. Retrieved at: http://www.energy.sc.gov/files/view/SC%20Energy%20Freedom%20Act_summary%2009.012.2019.pdf.

[98] South Carolina Public Service Commission (2020, December). Order No. 2020-832. P. 18.

utilities commissions and a broader community of stakeholders. Despite the presence of these alternative scenarios, Duke Energy clarifies that it considers only its 'base cases' as "suitable for planning purposes."[99] A table summarizing the six scenarios is provided below.

***Table C-1.*** *Duke Energy's Combined Integrated Resource Plan Scenarios*

| **Scenario Name** | **Base w/o Carbon Policy** | **Base w/ Carbon Policy** | **Earliest Practicable Coal Retirements** | **70% $CO_2$ Reduction: Wind** | **70% $CO_2$ Reduction: SMR** | **No New Gas** |
|---|---|---|---|---|---|---|
| **Relevant Commission Direction** | n/a | Directed by NCUC[100] | Directed by NCUC[101] | Directed by NCUC[102] | Directed by NCUC[103] | Requested by stakeholders |
| **Planned new gas generation by 2035 (MW)** | 9,600 | 7,350 | 9,600 | 6,400 | 6,100 | 0 |
| **Total Solar online by 2035 (MW)** | 8,650 | 12,300 | 12,400 | 16,250 | 16,250 | 16,250 |
| **Total New Wind by 2035 (MW)** | 0 | 750 | 1,350 | 5,500 | 3,100 | 5,800 |
| **Total New Nuclear by 2035 (MW)** | 0 | 0 | 0 | 0 | 1,350 | 700 |
| **Total New Storage by 2035 (MW)** | 1,050 | 2,200 | 2,200 | 4,400 | 4,400 | 7,400 |
| **Carbon Reduction Achieved by 2030 \| 2035** | 56% \| 53% | 59% \| 62% | 64% \| 64% | 70% \| 73% | 71% \| 74% | 65% \| 73% |
| **Present Value Revenue Requirement through 2050 ($, billions)** | $79.8 | $82.5 | $84.1 | $100.5 | $95.5 | $108.1 |
| **Dependent on supportive policy?** | Not dependent | Slightly dependent | Moderately dependent | Mostly dependent | Entirely dependent | Entirely dependent |

[99] DEC IRP Report, p. 97.

[100] NCUC, (2020, April), P. 7.

[101] NCUC, (2020, April). P. 8.

[102] NCUC, (2020, April)., p. 9.

[103] *Ibid.*

Duke's six scenarios provide a window into Duke's strategy for planning its portfolio under emerging climate risks. The scenarios are briefly summarized below.

- The **Base Case without Carbon Policy** provides a resource plan according to Duke's conventional, historical planning process.
- The **Base Case with Carbon Policy** adds a modest additional cost to carbon emissions, starting at $5 per ton in 2025 and escalating by $5 per year.
- **Earliest Practicable Coal Retirements** does not include a carbon policy, but retires coal plants at the earliest possible date, given necessarily transmission and distribution upgrades.
- The **70 percent $CO_2$ Reduction Scenarios** demonstrate two potential portfolios that would meet the North Carolina Clean Energy Plan scenarios of 70 percent carbon reduction (from 2005 levels) by 2035. One assumes the availability of offshore wind resources for the Carolinas; the other assumes the viability of small, modular nuclear reactors (SMRs).
- Finally, the **No New Gas** scenario provides Duke Energy's perspective on what a no-new-gas planning portfolio would look like.

With the exception of the No New Gas portfolio, each of Duke's presented scenarios involve a substantial buildout of gas-fired generation, from 6.1 gigawatts to 9.6 gigawatts (for context, the total gas portfolio between DEC and DEP has a current capacity of approximately 12.4 gigawatts). The portfolios also expect continued investment in solar resources in the Carolinas, up to 16.2 gigawatts in the high-solar scenarios. Depending on the scenario, wind, storage, and nuclear resources are also tapped to meet energy needs in the Carolinas.

On the other hand, the base cases do not represent a substantial departure from previous integrated resource plans in terms of their treatment of solar and gas assets. Table C-2, from Duke Energy's ESG Analyst day in October 2020, show selected attributes of the 2019 and 2020 base cases. Although coal retirements have changed significantly according to NCUC direction and new gas investment has decreased, the broad outlines of the plan are quite similar.

***Table C-2.*** *Comparing selected attributes of Duke Energy's 2019 and 2020 IRPs in the Carolinas*[104]

| | **2019 IRP Base with Carbon Policy** | **2020 IRP Base without Carbon Policy** |
|---|---|---|
| System $CO_2$ Reduction (2030 \| 2035) | 50% \| 48% | 59% \| 62% |
| Total Solar [MW] | 8,400 | 8,650 |
| Incremental Wind, Onshore and Offshore Combined [MW] | 0 | 0 |
| Incremental SMR Capacity [MW] | 0 | 0 |
| Incremental Storage [MW] | 550 | 1,050 |
| Incremental Gas [MW] | 11,550 | 9,600 |
| Coal Retirements by 2035 [MW] | 6,000 | 7,000 |

The final two rows in table C-1 represent Duke Energy's assessment of the financial and policy requirements of these scenarios. Duke Energy identifies the base case without carbon policy as the most affordable and the least policy-dependent option, while the No New Gas scenario is conversely the least affordable and most policy-dependent.

It is important to contextualize these assessments. First, portraying costs as present-value through 2050 may not provide a straightforward picture of cost impacts. The costs of assets built or purchased later in the planning horizon will be discounted more steeply, and costs incurred after 2050 are not included

[104] Duke Energy (2020, October). Delivering Sustainable Value: Our ESG Progress and Promise. Retrieved at: https://www.duke-energy.com/_/media/pdfs/our-company/investors/news-and-events/esg-investor-day-presentation.pdf?la=en.

in Duke's assessment. By contrast, assets built or purchased early in the planning horizon will be discounted little and may be recovered completely by 2050.

Second, these assessments provide an incomplete picture of Duke Energy's exposure to risks and opportunities, including climate-related risks. If any of the proposed conventional plants were to be out-competed by renewable resources mid-way through their expected lifetime, for example, the stranded asset costs could be borne by ratepayers even as Duke Energy continues to invest in new generation resources.

### iii. Treatment of Climate Risk within the Integrated Resource Plans

The 2020 IRPs represent a critical junction in Duke Energy's response to climate risks and opportunities. The IRP planning horizon of 15 years encompasses exactly half of the time between now and 2050, the common goal for a carbon neutral power sector. Investments made in the next 15 years will almost certainly be in operation in 2050, and proposed gas plants under some proposed scenarios will have engineering lifetimes into the 2070s. Given the emerging materiality of climate risk to Duke Energy shareholders, customers, regulators, and legislators in the Carolinas, a climate-risk informed resources plan would be in the public interest.

Unfortunately, the integrated resource plans are light on details in terms of meeting their commitments and mitigating long-term climate-related risk. The Commission-directed scenarios present a relatively robust picture of what meeting short-term 2030 goals are, but very few details are provided on pathways between 2030 and Duke's ultimate net-zero by 2050 commitment. Modest emissions reductions in the short-term emerge from Duke Energy's decision to expand gas generation to replace its coal fleet, but such a decision necessarily 'locks in' new emissions for decades as gas-fired power plants operate for their engineered lifetime.[105]

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[105] Erickson, P., Kartha, S., Lazarus, M., Tempest, M., (2015, August). Assessing Carbon Lock-in *Environmental Research Letters.* Retrieved at: https://dx.doi.org/10.1088/1748-9326/10/8/084023.

Looking to other jurisdictions with zero-by-2050 commitments may be instructive. Utilities in California, for instance, are proposing no new gas plants, opting instead to operate the ones that are already existing.[106] In Virginia, Dominion revised their integrated resource plan after the passage of the zero-by-2050 Virginia Clean Economy Act, noting that "significant build-out of natural gas generation facilities is not currently viable, with the passage by the General Assembly of the Virginia Clean Economy Act of 2020."[107] The plans contemplated in Duke Energy's IRPs in the Carolinas are out of step with these examples. If implemented as written, the plans would create a material tension between operating a newly-built fleet of gas-fired generation through their engineering lifetime and meeting a net-zero carbon commitment.

Duke Energy's IRPs do include a high-level discussion of long-term compliance with its carbon goals and reconciling a gas buildout with a pathway toward net-zero emissions. The options discussed by the company merit consideration. In particular, the IRP mentions technological solutions such as green hydrogen or renewable, zero-emission gas. While analysts have found these technologies may have a feasible role in a zero-carbon electricity system, scaling these technologies to completely replace fossil fuel needs for existing plants would entail transformative, national investment.[108] The IRPs do not appear to consider or quantify the additional costs of these investments, and therefore do not meaningfully engage with the economic implications of these technological fixes within the Plans.

In lieu of technological fixes, Duke Energy has offered a financial solution through accelerated depreciation, recovering the value of gas-powered plants much more quickly than the plant's

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[106] Roth, S., (2020, September). "Boiling Point: California won't need to kill fossil fuel plants. They're dying of old age." *LA Times.* Retrieved at: https://www.latimes.com/environment/newsletter/2020-09-24/fossil-fuel-plants-ladwp-methane-stranded-assets-boiling-point.

[107] Virginia Electric and Power Company (2020, March). Motion for Relief from Certain Requirements Contained in Prior Commission Orders and for Limited Waiver of Rule 150. Commonwealth of Virginia State Corporation Commission Case No. PUR-2020-00035. Retrieved at: https://scc.virginia.gov/docketsearch/DOCS/4m0c01!.PDF.

[108] Phadke, A., Aggarwal, S., O'Boyle, M., Gimon, E., Abhyankar, N., (2020, September). Illustrative Pathways to 100 Percent Zero Carbon Power by 2035 Without Increasing Customer Costs. Energy Innovation. Retrieved at: https://energyinnovation.org/wp-content/uploads/2020/09/Pathways-to-100-Zero-Carbon-Power-by-2035-Without-Increasing-Customer-Costs.pdf.

anticipated lifetime. The Integrated Resource Plans contemplate shortening the "lifetime" of gas plants to twenty-five years,[109] and Duke executives have publicly discussed accounting lifetimes as short as fifteen years.[110] Accelerated depreciation used in this way would allow Duke Energy to build new gas-fired generation with the expectation that these assets would become stranded midway through their lifetimes, while charging ratepayers a premium and insulating the utility from any stranded value. The extra costs to ratepayers of stranded gas assets, accelerated depreciation, or the costs of new generation to replace stranded gas assets are not reflected in the Integrated Resource Plans as presented.

Despite discussion of potential technological and financial alternatives, the Duke Energy Integrated Resource Plans do not adequately explore the exposure of the utility and its ratepayers to long-run climate-related risks. Especially as the Duke utilities contemplate a substantial buildout of new carbon-emitting generation, lack of clarity and transparency on these long-run risks should present concerns to policymakers, ratepayers, regulators, and utility management alike.

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[109] DEC IRP Report, p. 136.

[110] Morehouse, C,. (2019, October). "Duke VP likens gas plant buildout strategy to 15-year home mortgage on path to zero carbon." *UtilityDive.* Retrieved at: https://www.utilitydive.com/news/duke-vp-likens-gas-plant-buildout-strategy-to-15-year-home-mortgage-on-path/565328/.

## D. Assessing Carbon Stranding Risks in Duke Energy's 2020 Integrated Resource Plans

Previous sections of this report discussed the duty of utilities and regulators to ensure that capital investments by the utilities serve the public interest and meet a 'used and useful' standard throughout their lives. Assets that are no longer used and useful after construction present particularly salient risks to ratepayers because utilities have not always borne the full cost burden of these stranded assets. And, as new technologies and challenges transform the energy grid, the potential for stranded assets and increased costs allocated to ratepayers is higher than ever. Duke Energy's Integrated Resource Plans in the Carolinas introduce an acute 'carbon stranding' risk because of the anticipated build out of gas-fired generation in the face of climate-related risks and opportunities. This section will provide a quantitative assessment of the 'carbon stranding' risk to ratepayers in the 2020 Duke Energy Carolina and Duke Energy Progress IRPs.

This analysis takes inspiration from previous research by Oxford University's Sustainable Finance Programme[111] and Dr. Emily Grubert at Georgia Tech,[112] who modeled future carbon emissions from utilities' existing and proposed fossil generation fleets based on historical plant operation and estimated the impacts of carbon constraints. By comparing modeled future carbon emissions to low-carbon pathways and goals like the North Carolina Clean Energy Plan and Duke Energy's net-zero commitment, the analysis quantifies the discrepancy between stated commitments and modeled future operations, then attempts to quantify the costs of "righting the course" to meet carbon commitments after new fossil generation is operational.

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[111] Saygin, D., Rigter, J., Caldecott, B., Wagner, N., & Gielen, D., (2019, May). Power sector asset stranding effects of climate policies. Energy Sources, Part B: Economics, Planning and Policy 14:4, pp. 99-124. Retrieved: https://www.tandfonline.com/doi/abs/10.1080/15567249.2019.1618421.

[112] Grubert, Emily, (2020, December). Fossil electricity retirement deadlines for a just transition. *Science* 370:6521, pp. 1171-1173. Retrieved at: https://science.sciencemag.org/content/370/6521/1171.

Importantly, climate-related transition risks are not discrete: There is no single emissions 'cap' where climate risks begin to impede assets or operations, but risks accelerate as emissions exceed stated goals. This analysis uses Duke Energy's corporate commitments to 50 percent carbon reduction by 2030 and net-zero by 2050 as broad indicators for climate risk generally. To the extent that the Duke Energy utilities' portfolios are in compliance with their commitments, their portfolio is not considered at risk for carbon stranding. To the extent that the portfolio's projected emissions exceed the commitments, assets are at risk for carbon stranding. Breaching corporate commitments are just one of several causes for stranded carbon-emitting assets, as demonstrated by BloombergNEF[113] and Rocky Mountain Institute[114] analyses; in this case, the corporate commitment is used as a proxy for climate-related risk generally.

This analysis does not quantify all costs encompassed in an Integrated Resource Plan, and the 'carbon stranding' costs discussed throughout are just one component of the costs that ratepayers in the Carolinas will pay in the future. Nevertheless, these costs are of particular salience to ratepayers because of the likelihood that ratepayers will bear the burden, despite these units not meeting a future 'used and useful' standard. For more detailed information on the methods used in this analysis, see the Appendix.

### i. Projecting Future Emissions

Based on Duke Energy's statements identifying the base cases as suitable for planning,[115] analysis provided throughout will use the Base Case with Carbon Policy scenario, combined for both Duke Energy Carolinas and Duke Energy Progress.

[113] BloombergNEF.
[114] Gimon *et al.*

[115] DEC IRP Report, p. 97.

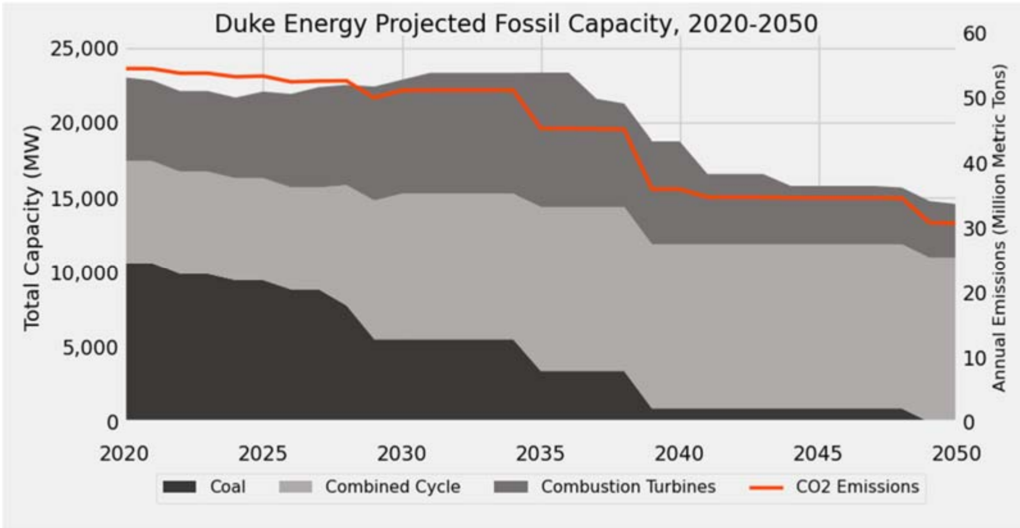



***Figure D-1.*** *Duke Energy Projected Fossil Capacity and Emissions, 2020-2050.*

Figure D-1 shows current and proposed capacity of conventional coal generation, gas combined-cycle units, and gas combustion turbines from year 2020 to 2050. The x-axis represents time from 2020 to 2050. The shaded areas show total capacity of fossil-fueled generating plants in Duke's portfolio (the left y-axis shows operating capacity in megawatts). While the portfolio sees a decrease in coal capacity through 2035 as legacy assets retire, the decrease is offset by increases in gas generation capacity. Then, after 2035, emissions and fossil capacity fall as legacy gas and combined-cycle plants retire. It is important to note that the planning horizon for the Integrated Resource Plans is 15 years, so the Base Case scenario does not include any further investments after 2035 (although it is likely that more capacity will be proposed and built in this time to meet resource adequacy constraints). Nevertheless, Duke Energy projects that over 14,000 megawatts of gas generation capacity will still be operational in 2050.

The red line shows projected carbon emissions for each year, based on the projected fossil fleet (the right y-axis shows total $CO_2$ emissions, in million metric tons). Carbon emissions for 2020 are projected based on the fleet's operation in the years 2016-2018; this analysis assumes that both existing and proposed plants will be operated with similar capacity factors and emissions per megawatt-hour generated as seen in 2016-2018 across the entire generation fleet. Using these assumptions, the red line



Exhibit TF-2

projects carbon emissions 2020-2050. Notably, these emissions totals do not reflect upstream emissions from gas production and transport.

Importantly, emissions are not projected to fall to near zero by 2050 based on the proposed portfolio and Duke's typical operation of this portfolio. In fact, they decline just 44 percent between 2020 and 2050. These projections represent a substantial departure from the Company's commitment to net-zero by mid-century, assuming that Duke Energy is not planning to use offsets for tens of millions of tons of emissions per year. Figure D-2 shows the difference between a linear path to the Company's goal and projected emissions based on its portfolio. By 2050, the difference between projected emissions for the Carolinas and Duke Energy's corporate commitment is approximately 30 million metric tons.

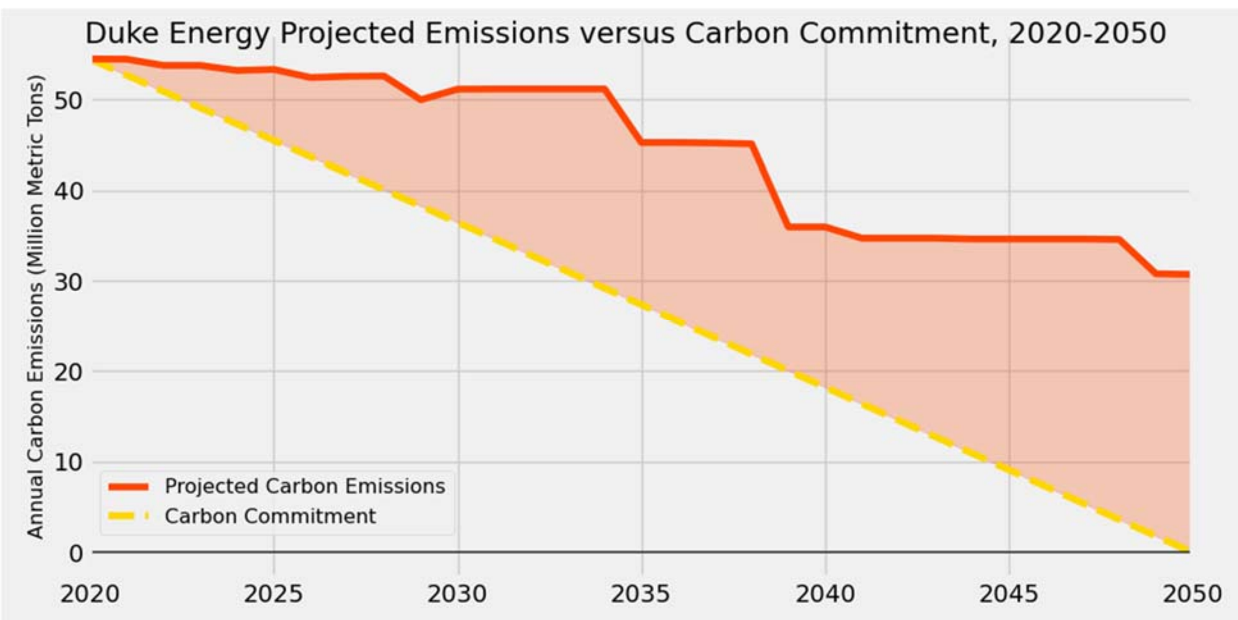



***Figure D-2.*** *Duke Energy Projected Emissions versus its net-zero commitment, 2020-2050.*

The large difference between these carbon projections and Duke Energy's commitment highlight a discrepancy between Duke Energy's current operating protocol and its ambitions for 2050. If Duke pursues its base-case integrated resource plan and plans to meet its commitments, two options present themselves: either the plants must be downrated or shut down altogether before their operational lifetimes are over, or Duke Energy will need to invest substantial capital in hypothetical technologies to decarbonize their existing generation. Either way, a dramatic shift will be needed, and it will create additional, unnecessary costs for ratepayers.

### ii. The Cost of Carbon Stranding

As shown above, Duke Energy's portfolio in the Carolinas is likely to exceed its corporate net-zero by 2050 commitment if plants are allowed to operate as normal. Therefore, Duke Energy will need to either use plants less than expected or remove them from the operating fleet earlier than expected to maintain compliance with their carbon commitment.

Analysis presented here attempts to characterize that phenomenon. First, the model determines how much carbon-emitting capacity would be taken offline every year to continue to meet carbon constraints. Then, the model calculates the depreciation and return on investment costs to ratepayers for stranded capacity (ratepayers are presumed to continue to pay for assets that have been taken offline until their expected retirement date). Emissions are modeled for each year, starting with 2020 and through 2050. If the modeled emissions are higher than the carbon commitment pathway shown in Figure D-2, then units are taken offline—effectively 'stranded'—until the modeled emissions are in compliance with carbon commitments. The model completes this process for every year, 2020-2050, continuing to remove additional capacity as needed to meet carbon constraints. For the purposes of this exercise, fossil generation units are retired and 'stranded' in order by technology (coal, then combined cycle, then combustion turbine), then by carbon intensity (most carbon-intense generation first), then by age (oldest first). Combustion turbines are preserved because they are most likely to be used as 'peaking' resources in concert with renewables.

To better understand the financial impacts of carbon stranding, a look at an individual plant may be helpful. 'Carbon stranding' of a combined-cycle gas plant planned to enter operation in 2035 is presented in Figure D-3.

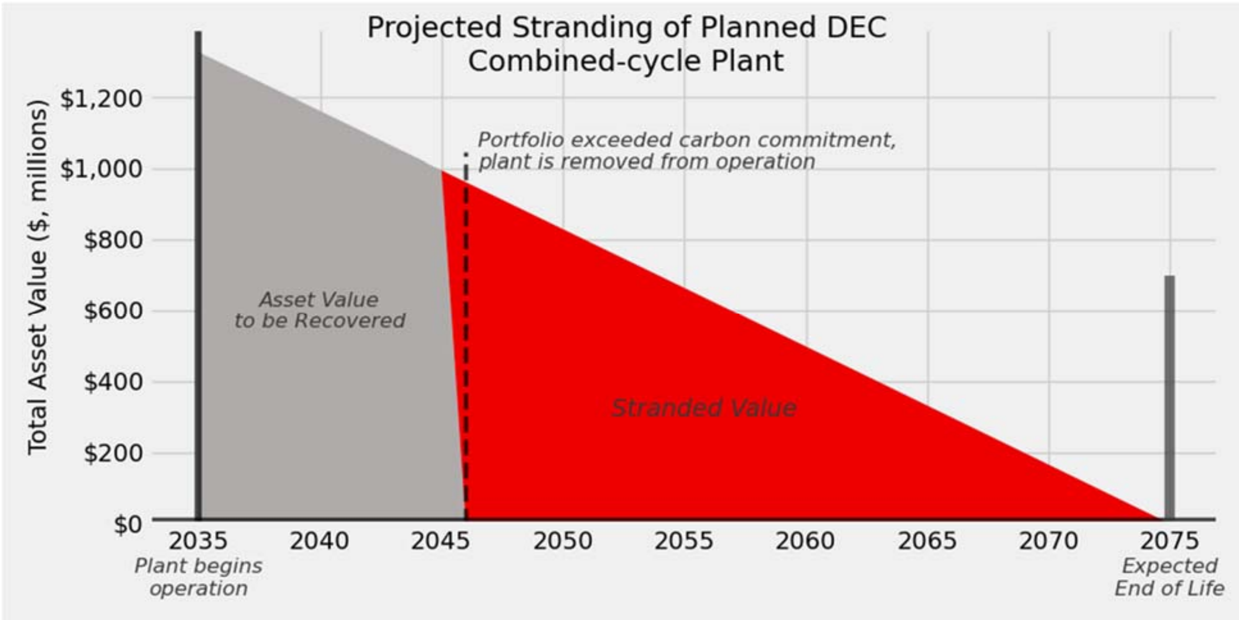



***Figure D-3.*** *Asset value and stranding of Duke Energy Carolinas combined-cycle gas plant, planned to be completed in 2035.*

This plant is planned to complete construction in December 2034 and enter operation in 2035. The total amount that ratepayers are expected to pay for the plant, including return on investment, is $1.4 billion. Each year, the asset's value depreciates over its 40-year lifetime until a planned retirement year of 2075. During the carbon-constrained run, however, the portfolio exceeds its carbon commitment in 2045. Because all coal plants and older combined-cycle plants had already been retired, this plant is removed from generation, stranding its remaining value. In this example, ratepayers would continue to pay the depreciation and return-in-investment on this asset even though it was removed from generation for another 30 years, totaling over $1 billion.

A portfolio-level look at the carbon-constrained portfolio following Duke Energy's Base Case with Carbon Policy is presented in Figure D-4.

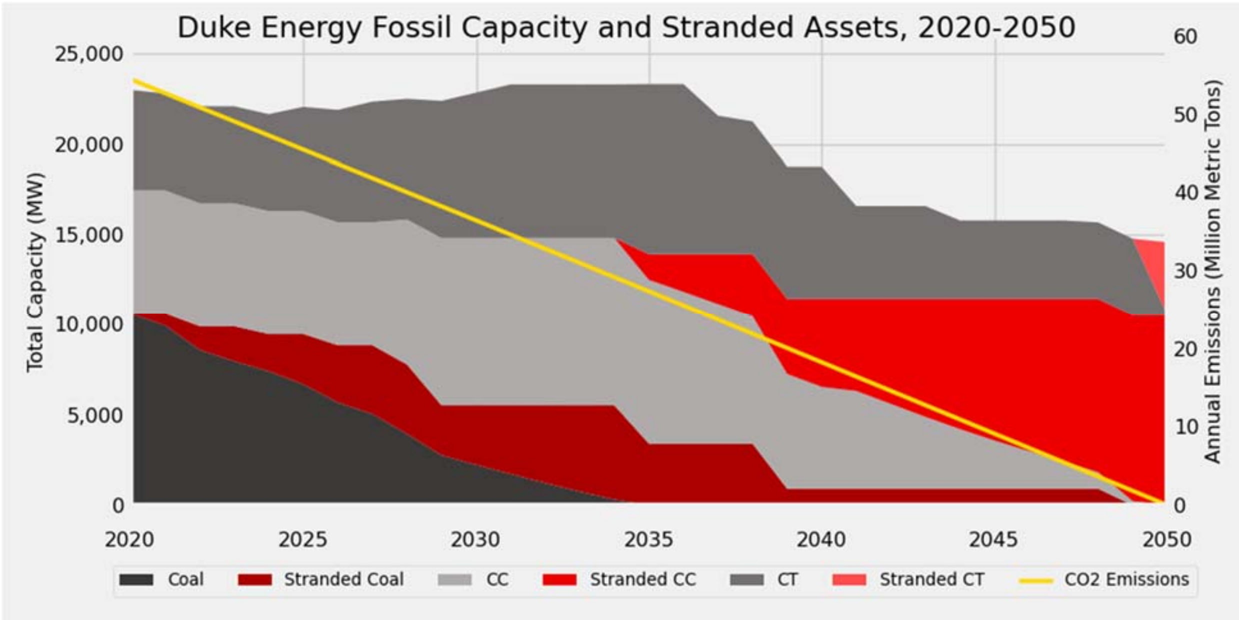



***Figure D-4.*** *Duke Energy Portfolio, with carbon stranded assets to meet climate commitments.*

In Figure D-4, areas shaded in red represent units and capacity that have been taken offline and 'stranded' in order to meet climate commitments. Additional carbon stranding occurs in every year, 2020-2050, with coal exiting the portfolio entirely in 2034 and a substantial amount of combined cycle assets are retired by 2040. Notably, no combustion turbines are retired until 2049-2050. This is because combustion turbines' capacity factors are very low—often below 5 percent—and therefore they contribute very little to total emissions.

Duke Energy reports capital costs for each generation plant in its reporting to the Federal Energy Regulatory Commission every year, and this analysis uses Duke's 2018 FERC filings to calculate annual depreciation and return-on-investment for each plant. Depreciation and return costs paid by ratepayers for carbon stranded assets represents carbon stranding costs. Total stranding costs for the portfolio, 2020-2050, are provided in Figure D-5.



Exhibit TF-2

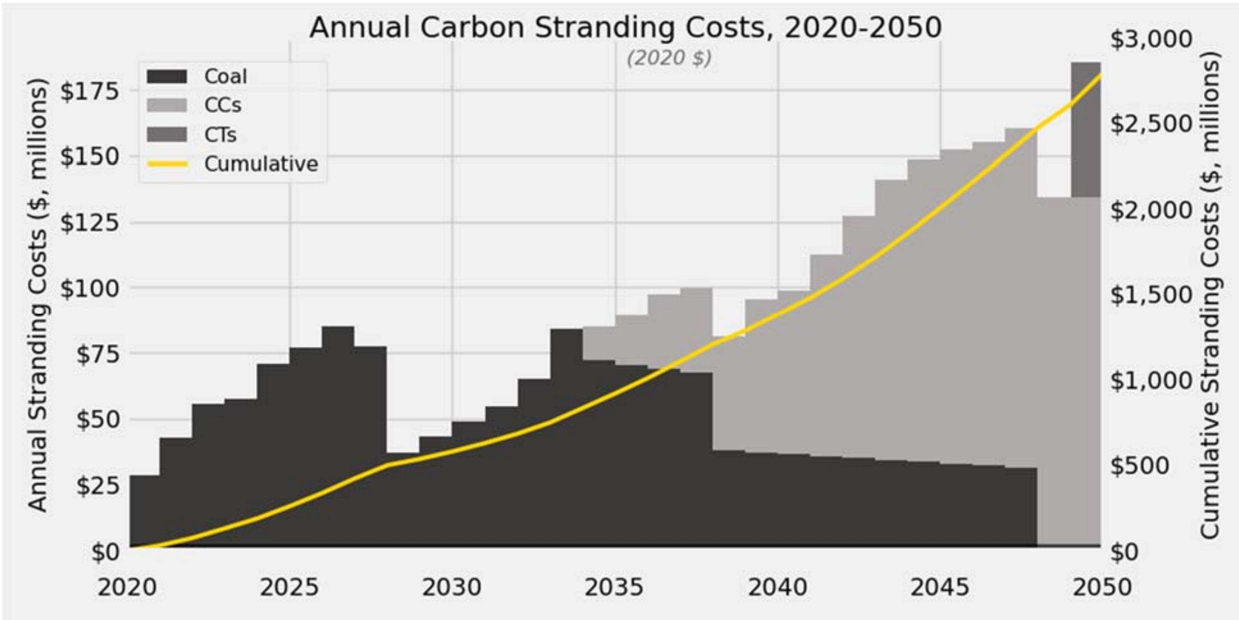



***Figure D-5:*** *Annual and Cumulative Carbon Stranding Costs, 2020-2050. All amounts are in millions USD, adjusted for inflation.*

Through 2035, annual carbon stranding costs to ratepayers are on the order of $50 million per year. By 2050, though, carbon stranding costs increase to as much as $175 million per year. Cumulatively from 2020 to 2050, this analysis projects that carbon stranding costs would accumulate to $2.8 billion in 2020 dollars by 2050. Notably, because combustion turbines are less capital-intensive than combined-cycle or coal plants, they have a relatively small contribution to stranding costs through 2050.

Despite 2050 being the target year of Duke's carbon commitment, gas generation would still be online and would therefore still create costs for ratepayers after 2050. Figure D-6 extends the previous figure to the end of the engineering lifetime of the last proposed plant in 2075.

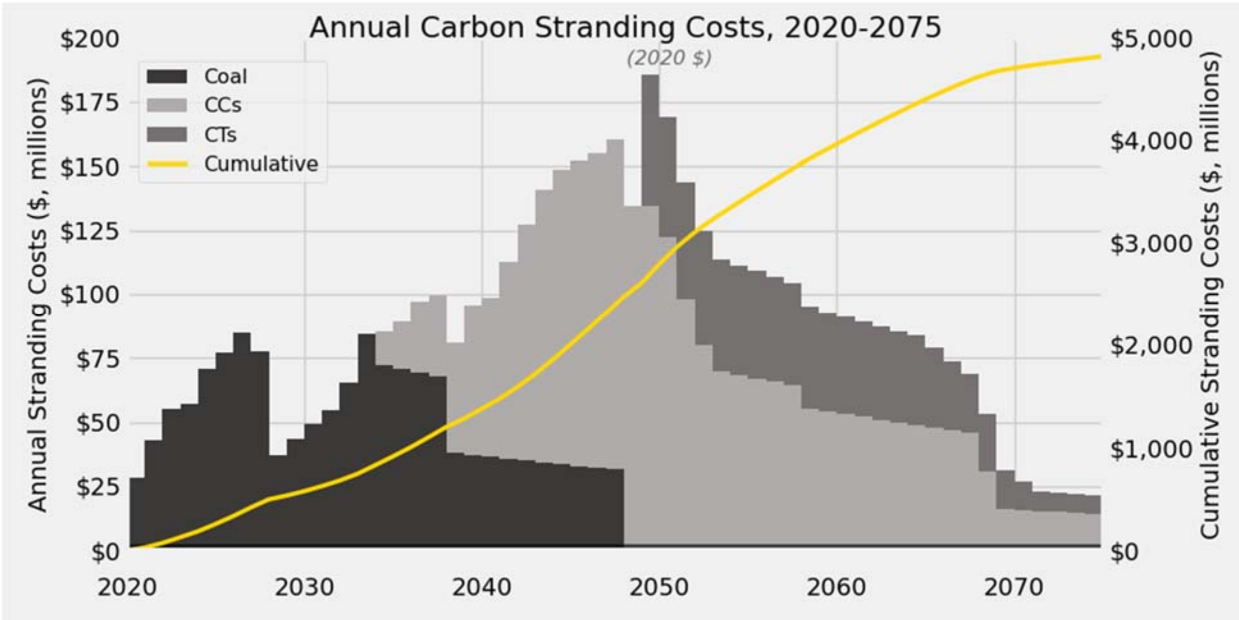



***Figure D-6.*** *Annual and Cumulative Carbon Stranding Costs, 2020-2075. All amounts in millions USD, adjusted for inflation.*

Ratepayers would continue to pay off non-operational gas assets through 2075. Over the lifetime of all of these assets, carbon stranding costs would accumulate to about **$4.8 billion** in 2020 dollars, exceeding the total stranded investment cost to Duke Energy and Dominion Energy combined on the Atlantic Coast Pipeline by over $1 billion. If this sum were to be invested in utility-scale solar at 2019 prices, $4.8 billion could drive almost 3.4 gigawatts of additional solar in the Carolinas. Using a social discount rate appropriate for discounting climate-related costs, the present value of carbon stranding in Duke Energy's Integrated Resource Plans in the Carolinas is **$3.3 billion**.[116] To put this number in context, $3.3 billion represents a **present value cost of $900 to every residential Duke customer in the Carolinas.** Key values from this analysis are presented in Table D-1.

[116] In its recommendations to the New York State Energy Research and Development Agency (NYSERDA), the research institution Resources for the Future provided climate-related costs at 0, 1, 2, and 3 percent discount rates. This analysis uses a mean discount rate of 1.5 percent. See https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf for additional details.



Exhibit TF-2

**Table D-1.** *Key Results of Duke Energy Carbon Stranding Analysis*

| | |
|---|---|
| **Projected GHG Emissions Overshoot in 2050** | 30 million metric tons |
| **Engineering lifetime of new-build combined-cycle gas plants** | 40 years |
| **Projected operational lifetime of new-build combined-cycle gas plants** | 12.3 years |
| **Total Carbon Stranding Costs** *(2020 $)* | $4.8 billion |
| **Present-Value Carbon Stranding Costs** *(2020 $)* | $3.3 billion |
| **Present-Value Cost per Residential Duke Customer** | $916.93 |

Notably, carbon stranding costs described above represent the total costs that ratepayers might be expected to pay for generation assets that would sit unused in order to avoid climate-related risks. The myriad other costs that would also be incurred in this scenario, including stranded transmission investments, costs for building zero-carbon replacement generation, additional operational costs as transitions occur years ahead of schedule, additional wear and tear on materials as the grid must reconfigure, and capital costs not directly associated with power plants that would need to be incurred to facilitate a transition to zero-carbon generation (e.g. new transmission lines), are not included. Therefore, the calculated 'carbon stranding' cost is only a part of the total cost burden for a disorderly transition to zero-carbon energy. However, these costs are unique in that they would be paid for assets that are neither used nor useful, and that Duke's ratepayers may be uniquely exposed to these costs.

## E. Conclusion & Recommendations

This report began with an examination of the toolbox available to regulators as they work with vertically-integrated electric utilities to ensure the electric grid is planned and operated in the public interest. The fact is that many of these tools are not built for the 21st century. Assumptions about a steady environment for electricity and the continued dominance of conventional, fossil-fueled generations have been disrupted by the increasingly distributed and decarbonized grid unfolding across the world today.

Increased attention paid by financial institutions like the G20 and the Commodity Futures Trading Commission suggests that prudent management requires a risk-informed approach. While scientists, analysts, financers, and managers are still working to understand the dynamics of these risks, there is no doubt that they will have substantial, long-run implications for how we make decisions on a day-to-day basis. The climate risk template used by the TCFD provides a framework for this kind of future decision-making.

For reasons explored earlier in this report, Duke Energy's 2020 Integrated Resource Plan in the Carolinas represents an ideal case study for the incidence of climate risk. As Duke Energy faces pressure from increasingly affordable technology, ESG-interested shareholders, state policymakers, and an increasingly informed public tracking the corporation's climate commitments, these integrated resource plans simply must integrate climate-related risks in order to pursue the public interest for all stakeholders.

Based on the Plans' intended build-out of fossil generation without a clear plan or budget for decarbonizing these new plants in the future, there is reason to further investigate the incidence of these climate-related risks on utility's assets and operations. If Duke Energy has no plan or budget to decarbonize these plants, it may need to retire them early—creating 'stranded' costs as ratepayers pay for generation that is not in use. As decision-makers consider whether the Integrated Resource Plan is in the public interest, understanding the magnitude of these climate-related risks, including carbon stranding costs, is critical.

This report presents a high-level assessment of the magnitude of those risks, finding that 'carbon stranding' could cost ratepayers tens or hundreds of millions of dollars a year and as much as $4.8 billion over the next several decades. Notably, because this assessment does not include the cost of replacing stranded generation assets with zero-carbon generation, cost figures presented here are likely a substantial under-estimate.

To avoid these costs, utilities and their regulators can and should add new tools to their toolkit to ensure their planning decisions are prudent and in the public interest. This report concludes with a few recommendations for utilities and their regulators to integrate a climate-risk perspective into their planning activities.

**For Regulators:**

- Affirmatively find that climate-related costs are material to utilities' business operations, and that prudent management of the utility requires serious consideration of these risks.
- Identify management of climate-related risks through mid-century as a critical component of least-cost, just and reasonable integrated resource plans.
- Require integrated resources plans to include explicit consideration of climate risks.
- Add a requirement that utilities address their zero-carbon transition plans beyond the 15-year planning horizon, including a stranded asset screen and end-of-life plans for all existing and proposed fossil-fueled generation.
- Utilize the 'used and useful' test to lighten the burden on ratepayers for stranded assets.
- Reject integrated resources plans that do not adequately demonstrate that carbon-emitting assets will not be stranded midway through their engineering lifetimes.
- Integrate consideration of climate-related risks into assessments of whether individual projects meet the requirements for a certificate for public convenience and necessity.
- Reject applications for individual carbon-emitting generation assets that do not contemplate climate-related risks and a low-carbon transition.

**Utilities:**

- Incorporate climate-related risks and opportunities into decision-making at multiple levels in the organization, not just at the corporate officer level. Climate-related risks will be material and substantial whenever and wherever utilities are planning multi-decadal investments.
- Aim for complete transparency, not only to shareholders but to all stakeholders, regarding the exposure and magnitude of climate-related risks and opportunities.
- Invest in analytical capabilities to better understand the impacts of climate-related risks, both physical and transition, on the utility's assets and operations.
- Provide robust, transparent discussion of how current resource plans will be reconciled with net-zero carbon goals (including in cost projections and investment plans), as well as other climate-related risks. If additional zero-carbon retrofits are contemplated, budget for them within resource planning procedures. If stranding or accelerated depreciation is anticipated, include these costs.
- Present credible, long-term strategies for meeting carbon commitments as a part of demonstrating the prudence and necessity of new investments in generation.
- Continue policy dialogue with state policymakers on zero-carbon planning across the economy.
- Use a wide range of load forecast, resource deployment, and carbon pricing scenarios that allow for a robust consideration of the clean energy transition.

# Appendix: Technical Specifications

This appendix summarizes the technical details of the emissions model used in this report.

The analysis projects carbon emissions from the fleet of large generation plants owned and operated by Duke Energy in the Carolinas. It shares similarities with other recent projections of carbon emissions and assessments of the implications of carbon constraints on the generation fleet from the University of Oxford Sustainable Finance Programme and Dr. Emily Grubert at tthe Georgia Institute of Technology.[117] This outline follows the broad outline of Saygin and Caldecott's 2019 study, which projects future emissions through 2050 for a generation portfolio given historical operation behavior, then models removal of units from the fleet in order to meet carbon constraints and estimates the costs of removing these units. In this case, a similar procedure is applied to Duke Energy's current and proposed generation fleet, as described in Duke Energy's 2020 Integrated Resource Plans.

Inputs for this analysis are generally taken from the Catalyst Cooperative's PUDL database, an open-source compilation of publicly available plant, unit, and utility-level data based on separate datasets from the Energy Information Administration, Environmental Protection Agency, and Federal Energy Regulatory Commission. Specific details on these inputs are provided below.

[117] Deger Saygin, Jasper Rigter, Ben Caldecott, Nicholas Wagner & Dolf Gielen (2019) Power sector asset stranding effects of climate policies, Energy Sources, Part B: Economics, Planning, and Policy, 14:4, 99-124, DOI: 10.1080/15567249.2019.1618421; *and* Emily Grubert *et al 2020 Environ. Res. Lett.* **15** 1040a4.



Exhibit TF-2

### i. Unit-level inputs and processing:

To assess current emissions and project future emissions, this analysis combines data at a unit and plant level.

**Appendix Table 1:** Unit- and Plant-level Data Inputs

| Input | Level | Source |
|---|---|---|
| Capacity (MW) | Unit | EIA 860 |
| Carbon Emissions (Metric Tons $CO_2$ ) | Unit | EPA Continuous Emissions Monitoring System |
| Plant Construction Year | Plant | FERC Form 1 |
| Net Generation, 2016-2018 (MWh) | Plant | FERC Form 1 |
| Capacity Factor, 2016-2018 (%) | Plant | FERC Form 1 |
| Total Capacity Cost ($/MW) | Plant | FERC Form 1 |

To project future emissions from existing plants, this analysis uses average capacity factors (annual kilowatt-hours per kilowatt) and emissions factors (tons $CO_2$ emitted per net megawatt generated) 2016-2018. For projected new-construction units or units for which data was not available, this analysis uses fleet average capacity factors and emissions factors by technology (conventional steam coal plant, gas-fired combustion turbine, gas-fired combined cycle plant, gas-fired steam turbine, oil-fired turbine). Because gas-fired steam turbines and oil-fired turbines make up such a small portion of the total portfolio capacity, their capacity and emissions are not included in graphics in the report body.

Although this report generally treats generation units separately, it was not possible to estimate operation of combined-cycle gas plants if one unit was taken offline. Instead, each combined-cycle plant was treated as a single unit.

### ii. Portfolio-level Inputs

Portfolio-level inputs are taken from the Duke Energy Carolinas and Duke Energy Progress 2020 Integrated Resource Plans, alongside other Duke inputs.

This model examines the Base Case with Carbon Policy for reference in terms of the timing and size of new generation investments, as well as retirements of existing plants. For plants not given an anticipated retirement date in the Integrated Resource Plans, this assessment used a baseline estimate of 40 years, consistent with the engineering lifetimes listed in the EIA's 2020 Annual Energy Outlook. To model the costs of new generation investments, the analysis pulls from research compiled as a part of EIA's Annual Energy Outlook. Based on the proposed or estimated lifetime, an annual depreciation or capital recovery factor—in terms of dollars per megawatt per year—is constructed.

**Appendix Table 2:** Portfolio-level Data Inputs

| Input | Source |
|---|---|
| Intermediate 2030 Carbon Goal (50% by 2030) | 2020 Duke Energy Integrated Resource Plan stakeholder materials |
| Timing and size of new generation investments | 2020 Duke Energy Carolinas and Duke Energy Progress Integrated Resource Plan |
| Technical Specifications of New Investments | US Energy Information Administration Annual Energy Outlook |
| Unit Retirement Year | 2020 Duke Energy Carolina and Duke Energy Progress Integrated Resource Plans; if not contemplated, assumed 40 years |
| Estimated rate of return on investment | Average of proposed rate of return on investment from most recent DEC and DEP rate cases in North and South Carolina |
| Additional capital expenditures | None. Only capital expenditures reported in FERC 1 and rate of return are included. Revenue requirements due to taxes, AFUDC, or CWIP are not included. |

### iii. Model Operation

Using unit-level capacity factors and emissions factors calculated as described above, this model calculates annual fleet-level emissions. As a point of validation, the emissions calculated by this model reasonably approximate DEC and DEP statements on fleet emissions. Moving forward year-by-year, the model calculates carbon emissions each year, adjusting as proposed generation comes online or existing generation reaches its planned retirement year or the end of its engineering lifetime. Outputs of this run of the model, called the "IRP case," are shown in Figure D-1 of the report body.

Next, the model creates a carbon constraint by linearly interpolating between projected 2020 emissions, Duke Energy's corporate goal of a 50 percent reduction from 2005 levels by 2030, and the Corporation's net-zero-by-2050. Three caveats should be noted: First, the constraint targets zero emissions in 2050 because of concerns with negative-emissions technology or offsets discussed in the report body. Second, this model assumes that Duke Energy plans to comply with its goals via a strict linear interpolation between targets. Third, the constraint assumes that Duke Energy Carolinas and Duke Energy Progress will hold to the same constraint as Duke Energy Corporation overall.

On the second run, the model applies this carbon constraint to annual emissions. If projected emissions are in excess of the carbon constraint for a given year, the model chooses a unit to downrate or retire. The heuristic for which unit to downrate or retire is as follows: First, it selects by technology (coal, then gas combined-cycle plants, then gas combustion turbines), then by emissions intensity. If any units have the same modeled emissions intensity, the unit with the earliest installation year is removed first. Downrated or retired capacity is then put in a "stranded pool" until the asset reaches its planned or estimated retirement year. The model moves sequentially, 2020-2050, continuing to remove units from generation as needed. For each year any capacity from a plant is in the "stranded pool," the model calculates the total amount of capital recovery or depreciation costs associated with stranded capacity. These annual and aggregate depreciation costs form the "carbon stranding costs" shown in Figures D-4 and D-5 in the report body. Although all capacity is either retired or stranded in 2050, projected or estimated lifetimes for several units extend into the 2060s and 2070s.



Exhibit TF-2

# Energy Transition Institute

www.energytransitions.org

2021



Exhibit TF-2

**South Carolina Public Service Commission**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Exhibit TF-3**

**Duke Energy 2020 Climate Report**

# ACHIEVING A NET ZERO CARBON FUTURE

Duke Energy 2020 Climate Report

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE®

Exhibit TF-3

# Contents



Duke Energy published this Climate Report during the COVID-19 (coronavirus) pandemic. Learn about the company's response to this crisis at dukeenergyupdates.com.

**Exhibit TF-3**



# Executive Summary

As one of the largest electric and gas utilities in the U.S., Duke Energy embraces its responsibility not only to power the communities where our customers live and work, but also to address risks from climate change. Addressing the challenges climate change presents is a mission on which we all agree. We must double down on the hard work that will inform the technology, pace and cost of the transition, while always keeping affordability and reliability for our customers as our guiding beacons. Duke Energy will continue to help lead the effort to develop solutions to this complex challenge.

This report discusses how we are leaning in to this challenge and addressing climate risks by, first and foremost, reducing our own emissions and, secondly, by adapting our system to be more flexible and resilient.[1]

Our plans are guided by new carbon reduction goals that were announced in September of 2019. Duke Energy aims to reduce carbon dioxide ($CO_2$) emissions from electricity generation at least 50 percent below 2005 levels by 2030 and to achieve net-zero $CO_2$ emissions by 2050.[2]

We have already made significant progress toward our updated goals, reducing $CO_2$ emissions 39 percent since 2005, ahead of the industry average of 33 percent.[3] To build our path to net zero, we will work collaboratively with stakeholders and regulators in each of the states we serve to develop specific plans that best suit their unique attributes and economies. This will be an exciting transformation that evolves and adapts over time. This report offers insights into the complexities and opportunities ahead and provides an enterprise-level scenario analysis with an illustrative path to net zero, based on what we know today.[4]

This scenario analysis was conducted using our industry-standard resource planning tools and assuming normal weather (averages over the past 30 years). The major findings of this scenario analysis are:

- We are on track to achieve our 2030 goal of reducing $CO_2$ emissions from electricity generation by at least 50 percent from 2005 levels.
- The path to net zero by 2050 will require additional coal retirements, significant growth in renewables and energy storage, continued utilization of natural gas, ongoing operation of our nuclear fleet, and advancements in load-management programs and rate design (demand side management and energy efficiency). Importantly, this path also depends on the availability of advanced very low- and zero-carbon

[1] This report, like our 2017 Climate Report to Shareholders, is aligned with the disclosures recommended by the Task Force on Climate-related Financial Disclosures (TCFD).
[2] These goals are enterprisewide. Each jurisdiction will have a different trajectory toward achieving them.
[3] U.S. Energy Information Administration, *Monthly Energy Review*, March 26, 2020.
[4] This scenario analysis does not model specific climate policies but has helped us identify key attributes of policies that will help us achieve our goals. These are discussed in the policy risks section on page 15.



Exhibit TF-3

technologies that can be dispatched to meet energy demand. These "zero-emitting load-following resources" (ZELFRs) will need to be installed as early as 2035. This analysis projects that ZELFRs will make up 12 percent of the capacity mix and supply 30 percent of energy by 2050 due to their ability to operate at full output over extended periods regardless of weather conditions. See sidebar on ZELFRs.

- Our analysis also shows that while we project adding large amounts of renewable energy, natural gas units remain a necessary and economic resource to enable coal retirements and to maintain system reliability as we transition.[5] Natural gas – reinforced by adequate transport capacity – allows us to retire our remaining 16 gigawatts (GW) of coal and transition to net-zero $CO_2$ emissions by 2050 while maintaining affordability and reliability. Notably, as increasingly larger amounts of renewable energy and other zero-emitting resources are added, Duke Energy's natural gas fleet will shift from providing bulk energy supply to more of a peaking and demand-balancing role.

- We project continuing to need natural gas because, in jurisdictions such as ours where hourly demand for electricity is not well-correlated with hourly renewable generation, renewables are not operationally equivalent to natural gas generation, particularly for prolonged periods of cloudy weather and/or low wind speed conditions.

  - We conducted a "no new gas" sensitivity to stress-test this projection. We find that while energy storage can help address the capacity and energy gap created by retirement of coal units, installation and operational challenges arise as we attempt to rely on current commercially available storage technologies to provide intermediate and baseload capabilities.

  - For example, to enable coal retirements and accommodate load growth without adding natural gas, Duke Energy would need to install over 15,000 MW of additional four-, six- and eight-hour energy storage by 2030. That equates to a little over 17 times all the battery storage capacity installed nationwide today (899 MW).[6] The largest battery storage facility that exists in the world today is the Tesla-built 100-MW Hornsdale Power Reserve in Australia.[7] A larger 400-MW battery storage facility is currently under development in the Southeast.[8] These are important and encouraging developments, but it is notable that Duke Energy would need to build nearly 40 storage facilities like the one under development in the next nine years to reach

[5] Note that our analysis does include economic hurdles for natural gas to address the risk of stranded assets (see page 23 for discussion).

[6] EIA, U.S. Utility-scale battery storage power capacity to grow substantially by 2023, July 2019. https://www.eia.gov/todayinenergy/detail.php?id=40072 (showing 899 MW of battery storage as of 2019 and projecting 2,500 MW installed by 2023).

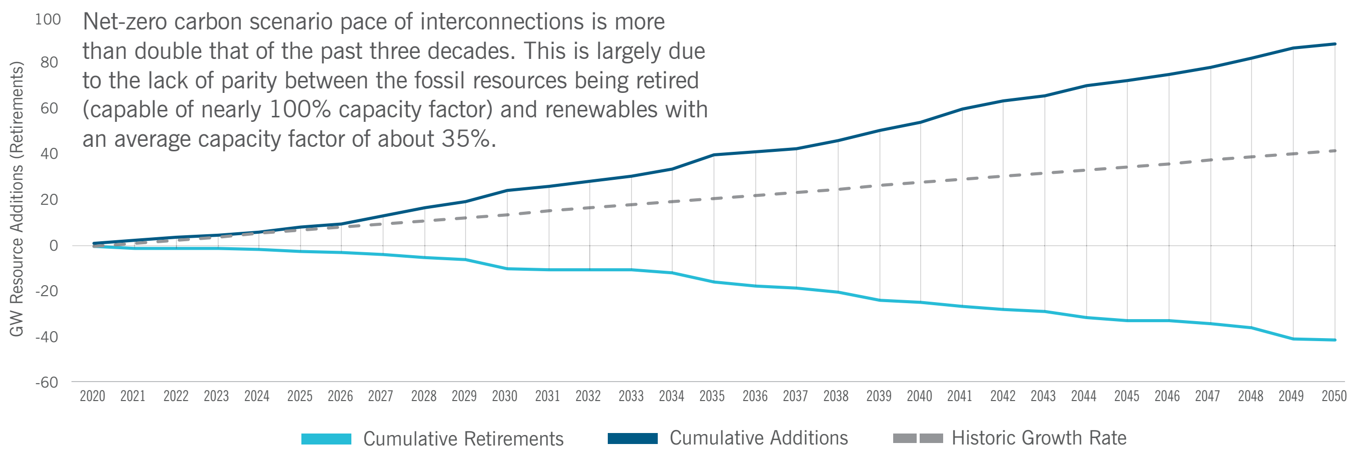
[7] https://hornsdalepowerreserve.com.au/

[8] http://newsroom.fpl.com/2019-03-28-FPL-announces-plan-to-build-the-worlds-largest-solar-powered-battery-and-drive-accelerated-retirement-of-fossil-fuel-generation

15,000 MW of storage. Due to this tight time frame, challenges would likely include regulatory approvals and permitting, interconnection studies and associated upgrades, and potential supply chain issues, considering the current early stage of the utility-scale battery storage industry.

- Taking this scale of battery implementation to real-world, reliable and affordable operations would require further detailed analysis and on-the-ground experience – among other factors – to determine operational feasibility. We are not aware of any electric utility in the U.S. that has attempted to serve customers reliably at scale with such a high proportion of capacity from energy storage. We discuss the detailed analysis needed before such implementation on page 29.
- If such an amount of storage is possible from an operational standpoint, we found that the incremental costs of achieving net zero under this sensitivity would increase by three to four times above that of the net-zero scenario that utilizes natural gas (even without including the likely significant additional costs for transmission and distribution system upgrades). These costs could especially have an impact on Duke Energy's low- and fixed-income customers and energy-intensive businesses.

- Achieving net zero, even with gas, will require an unprecedented and sustained pace of capacity additions. For example, we will need to add new generation to our system over the next three decades at a pace more than double the rate at which we added generation over the past three decades. This is illustrated in the chart below.




- In the net-zero carbon scenario, renewables (solar and wind) contribute over 40,000 MW of those additions, representing 40 percent of the summer nameplate capacity of Duke Energy's system by 2050 and generating the largest portion of energy. To put this into perspective, Duke Energy's total summer generating capacity today is approximately 58,000 MW and grows to over 105,000 MW by 2050. The requirement for such large needed additions arises because replacing traditional electric generating capacity with renewables plus storage is not a one-for-one proposition. Due to the intermittency of renewables, significantly more capacity must be built, even with storage available, to provide the same level of reliable electricity generation as a fossil plant. Therefore, achieving net zero will also depend on our ability to site, construct and interconnect new generation, transmission and distribution resources at an unprecedented scale in a timely manner.[9]

[9] See University of North Carolina, "Measuring Renewable Energy as Baseload Power," March 2018. https://www.kenaninstitute.unc.edu/wp-content/uploads/2018/05/Kenan-Institute-Report-Measuring-Renewable-Energy-as-Baseload-Power-v2.pdf



Exhibit TF-3



- Our modeling demonstrates that if these resources are integrated into the grid as forecast, we will be able to serve customers under normal weather, which is the way we have planned the system in the past, when the vast majority of resources were dispatchable over long durations (weeks rather than hours). More work is needed to better understand the ability of renewables and storage to meet capacity needs, and how that will change as more of these resources are added to displace conventional generation. We are already embarking on these analyses and expect that collective industry understanding will improve over time.
- While we did not explicitly account for transmission and distribution needs in this analysis, it should be recognized that retirements of certain coal (and, later on, gas) units, as well as the addition of large volumes of renewables and energy storage, will require substantial investments in our transmission and distribution systems. Federal and/or state policy changes may be needed in order to achieve such large transmission and distribution investments in a timely manner.

The actual pathway that Duke Energy takes to achieve net-zero carbon emissions by 2050 will be based on the availability and cost of evolving technologies, federal and/or state climate policies, and stakeholder and regulatory input and approvals. During the 2020s, significant innovation and technological advancement will be critical to ensure we have viable technology options by the 2030s.

To help enable these new technologies, we are committed to working with the private and public sectors to drive research, development and demonstration of technologies such as advanced nuclear; carbon capture, utilization and storage (CCUS); hydrogen and biofuel utilization for power generation; and longer-duration (up to seasonal) storage.

We are embracing this extraordinary challenge, collaborating with regulators, policymakers and other stakeholders to help develop the best policies and options that will reduce carbon emissions and meet the needs of our customers for affordability, reliability and sustainability.



Exhibit TF-3

## Zero-Emitting Load-Following Resources

Our analysis makes it clear that advanced very low- or zero-emitting technologies that can be dispatched to meet energy demand are needed for Duke Energy to transition to its net-zero carbon future. There are several technologies that could play the role of zero-emitting load-following resources (ZELFRs), such as:

- **Advanced nuclear** – Advanced nuclear includes a wide range of small modular light-water reactors (SMRs) and advanced non-light-water reactor designs. Small modular light-water reactors are closest to commercial deployment, with early designs targeting commercial operations in the mid-to-late 2020s. Advanced non-light-water reactor concepts are also under development and are expected to be commercially available in the 2030s.
- **Carbon capture, utilization and storage (CCUS)** – CCUS technologies for the power sector are in the early stages of deployment, with a few small-scale projects on coal having achieved commercial operation and several natural gas projects currently in development, spurred by the 45Q tax credit, which provides an incentive for utilizing or storing captured $CO_2$. Demonstration of CCUS at scale for natural gas power plants is an important milestone for commercial deployment in the power sector, as is building public, environmental and regulatory confidence around the transportation of captured $CO_2$ and its utilization and geologic storage.
- **Hydrogen and other gases (including renewable natural gas)** – Hydrogen and other low- or zero-carbon fuels are increasingly gaining attention for their potential to contribute to a net-zero carbon grid. For example, many existing natural gas turbines are already capable of co-firing hydrogen, and vendors are focused on developing models capable of firing 100 percent hydrogen. Key opportunities include cost-effectively producing hydrogen (or other gases, including renewable natural gas) from very low- or zero-carbon processes and ensuring safe and effective methods of transportation.
- **Long-duration energy storage** – Long-duration energy storage includes a wide range of thermal, mechanical and chemical technologies capable of storing energy for days, weeks or even seasons, such as molten salt, compressed/liquefied air, sub-surface pumped hydro, power to gas (e.g., hydrogen, discussed above) and advanced battery chemistries. These technologies are at various stages of research, development, demonstration and early deployment

Other technologies will also be important. We continue to explore pumped storage hydro opportunities (a mature technology), as well as advanced renewables (such as offshore wind and advanced geothermal and solar), energy efficiency and demand response.

Duke Energy is actively involved in efforts to advance research, development, demonstration and deployment of advanced technologies. For example, we are a founding member and anchor sponsor of the Electric Power Research Institute/Gas Technology Institute's Low Carbon Resource Initiative, which is a five-year effort to accelerate the development and demonstration of technologies to achieve deep decarbonization. And we have participated in extensive research over the past few years on CCUS, including, for example, a study of membrane-based carbon capture that was conducted at our East Bend facility in Kentucky. We are also involved in both the Midwest Regional Carbon Capture Deployment Initiative and the Midwest Regional Carbon Sequestration Partnership.

We are also a founding member of EEI's Clean Energy Technology Innovation Initiative, which is partnering with several non-governmental organizations (NGOs), including Clean Air Task Force, the Center for Climate and Energy Solutions, and the Bipartisan Policy Center, to identify areas for advocacy on advanced technologies.

Robust and sustained government support is vital to ensure the commercialization of these advanced technologies; Duke Energy will continue to advocate for sound public policies that advance this needed support.



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# Introduction

In the following sections, this report highlights Duke Energy's commitment to address climate change:

- **Governance** – discusses Board of Directors oversight, executive compensation and lobbying/ political expenditures policies.
- **Strategy** – discusses how various inputs inform and drive Duke Energy's plans to a net-zero carbon future.
- **Risk Management** – addresses Duke Energy's process for identifying physical and transition (policy and economic) risks, and measures for addressing these risks.
- **Metrics** – identifies the company's specific $CO_2$ reduction goals, progress toward those goals, as well as other greenhouse gas (GHG) metrics.
- **Scenario Analysis** – discusses our analysis of a net-zero carbon emissions scenario to provide insight into areas of near-term and longer-term focus needed to achieve our net-zero 2050 goal.

# Governance

## Board Committee Oversight

The Duke Energy Board of Directors understands the importance of climate change issues, as well as their significance to our employees, customers and communities, and recognizes the potential impact and opportunities for our business and industry. In 2019, the Board was instrumental in the development of Duke Energy's updated carbon reduction goals, including review and discussion at multiple meetings of the Corporate Governance Committee, along with insights from external experts at a full Board meeting.

Given the wide scope of climate risks, including physical, policy and economic risks, the Board and its committees are all actively involved in oversight, as shown in the table on the next page.

| BOARD OF DIRECTORS<br>RISK MANAGEMENT OVERSIGHT STRUCTURE | |
|---|---|
| **Corporate Governance Committee**<br>▪ Oversees risks related to sustainability, including climate risks<br>▪ Oversees risks related to public policy and political activities<br>▪ Oversees the company's shareholder engagement program, receives updates on shareholder feedback and makes recommendations to the Board regarding shareholder proposals, including those related to climate<br>▪ Evaluates the composition of the Board to ensure a proper mix of skills and expertise to oversee Duke Energy's risks and strategy | **Finance & Risk Management Committee**<br>▪ Oversees process to assess and manage enterprise risks, including climate risks (page 11)<br>▪ Oversees and approves major investments that are supportive of the company's climate strategy, such as renewables, grid modernization, natural gas and storage<br>▪ Oversees financial risks, including market, liquidity and credit risks |
| **Operations & Nuclear Oversight Committee**<br>▪ Oversees risks related to our nuclear fleet, our largest carbon-free resource, as well as risks related to our non-nuclear regulated operations<br>▪ Oversees operations and environmental, health and safety matters, including improvements at our generation facilities and coal ash basins to better withstand severe weather events (page 12) | **Regulatory Policy Committee**<br>▪ Oversees regulatory and policy risks related to climate change, including review of federal and state policies at every regularly scheduled meeting (page 15) |
| **Compensation Committee**<br>▪ Oversees risks related to our workforce and compensation practices, including those related to climate | **Audit Committee**<br>▪ Oversees the company's disclosures, internal controls and compliance risks, including those related to climate<br>▪ Oversees risks related to cybersecurity and technology |

The day-to-day direct management of climate and carbon-reduction policies is the responsibility of the company's federal government and corporate affairs team. This team reports to the executive vice president for external affairs and president, Carolinas region, who is a member of the Duke Energy senior management team and reports directly to the chair, president and chief executive officer. The federal government and corporate affairs group has organizational responsibility for developing Duke Energy's position on federal legislative and regulatory proposals addressing climate change and greenhouse gas emissions and for assessing the potential implications of such proposals to the company – as well as for engaging stakeholders to help shape our climate strategy. In addition, Duke Energy's state presidents have responsibility for developing the company's positions on state-level legislative



Exhibit TF-3

and regulatory proposals addressing climate change and greenhouse gas emissions, and for engaging stakeholders at the state level to help shape the company's climate strategy.

## Compensation

The Compensation Committee has designed our compensation program to link pay to performance, with the goal of attracting and retaining talented executives, rewarding individual performance, encouraging long-term commitment to our business strategy and aligning the interests of our management team with those of our shareholders. The Compensation Committee has aligned several performance metrics with our sustainability strategy, including:

- Zero-carbon generation – We incorporate a nuclear reliability objective and a renewables availability metric in our short-term incentive plan to measure the efficiency of our nuclear and renewable generation assets.
- Environmental events – To enhance our commitment to the environment, we incorporate a reportable environmental events metric into our short-term incentive plan.
- Customers – To prioritize the customer experience and their growing demands to be served by cleaner energy, we incorporate a customer satisfaction metric in the short-term incentive plan, which is a composite of customer satisfaction survey results for each area of business.
- Safety – Safety remains our top priority. We include safety metrics in both our short-term and long-term incentive plans based on the total incident case rate of injuries and illnesses among our workers to emphasize our focus on an event- and injury-free workplace.
- Governance – We continue to incorporate sound governance principles and policies in our compensation program that reinforce our pay for performance philosophy and strengthen the alignment of interests of our executives and shareholders.

Duke Energy continues to review its compensation program performance metrics with the Compensation Committee.

## Political Contributions and Lobbying

As a public utility holding company, Duke Energy is highly regulated and significantly impacted by public policy decisions at the local, state and federal levels. It is essential for us to engage in public policy discussions to protect the interests of Duke Energy, our customers, employees, shareholders and communities. Participation in public policy dialogues includes contributing to organizations, including trade associations, that advocate positions that support the interests of Duke Energy, our customers, employees, shareholders and communities.

Duke Energy has developed a robust governance program around our public policy engagement. The day-to-day management of our policies, practices and strategy with respect to public policy advocacy is the responsibility of the jurisdictional presidents at each applicable state level and our senior vice president for federal government and corporate affairs, who, along with other senior leaders across the company, make up a Political Expenditures Committee (PEC). The PEC is responsible for annually developing the company's political expenditures strategy and approving, monitoring and tracking our political expenditures. The company's Political Expenditures Policy sets out the principles governing corporate political expenditures and political action committee contributions. Under this policy, the senior vice president for federal government and corporate affairs provides a semi-annual update to the Corporate Governance Committee of the Board. This includes updates on the company's strategy and political expenditures, including payments to trade associations and other tax-exempt organizations that may be using the funds for lobbying and political activities. (See Duke Energy's Corporate Political Expenditure Reports).

In addition to our participation in trade associations for public policy engagement purposes, we participate in industry trade organizations for many non-political reasons as well, including business, technical and industry standard-setting expertise. As member-driven organizations, these trade associations take positions that reflect the consensus views of their members. We may not support each of the initiatives of every organization in which we participate or align in strategy with every position of every organization; however, in our interactions with them, we seek to harmonize the organizations' positions on climate change with those of Duke Energy. We believe our continued input into these discussions with organizations with whom we may not always totally agree enables us to educate others on our positions and enables us to better understand their positions.

# Strategy

## Informing Our View

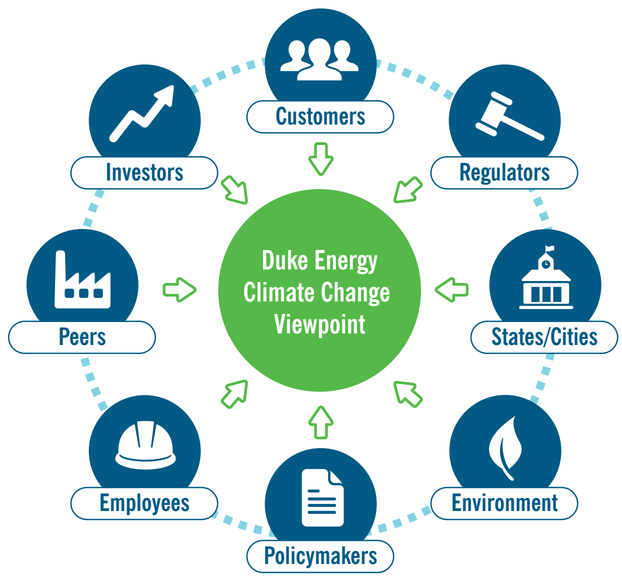
At Duke Energy, we are committed to leading in the effort to address greenhouse gas emissions and to build a cleaner, smarter energy future. As we talk with customers, investors and other stakeholders, reflected in the figure to the right, it's clear that they share that interest. It's also clear that unnecessarily compromising reliability and affordability, especially for our most vulnerable customers, is not an option.

An increasing number of our customers are calling for electricity from non-carbon-emitting sources. For example, Apple, BMW, Facebook and Google are all members of the "RE100," a coalition of companies committed to sourcing 100 percent of their electricity from renewable sources. In some cases, this is through a commitment to match 100 percent of the companies' electricity use with renewable energy purchases.

But it's much more than the interests of our large corporate customers. Counties and cities in Duke Energy's service territories have developed ambitious sustainability or 100 percent renewable energy goals, most by 2050. Further, North Carolina's governor issued an executive order followed by a Clean Energy Plan that calls for reducing greenhouse gas emissions from the power sector by 70 percent by 2030 and to achieve carbon neutrality by 2050. Additionally, climate change remains a prominent topic of discussion in federal political and policy arenas, as can be seen in proposals to address climate change being developed by Democratic and Republican leadership in Congress. The challenge inherent in these goals is not in their establishment, but rather in the development of the right mix of executable options to get the entire economy to net zero by 2050.

Climate change also continues to be a focus of engagement and discussion with the company's shareholders and employees. Both groups want to be sure we are recognizing and responding appropriately to the risks and opportunities that climate change presents.

To continue to power the lives of our customers, support the vitality of communities and exceed the expectations of our customers and stakeholders, we need to deliver energy that is cleaner and smarter than ever before.




## Accelerating Our Carbon Reduction Goals

We recognize the long-term challenge climate change presents and that reducing $CO_2$ emissions in the power sector is a major part of the effort to address this challenge. Given the input discussed above, our assessment of climate-related risks and opportunities, as well as the declining cost of renewables and sustained low cost for natural gas, in 2019 we updated our carbon reduction goal. We are confident that we can achieve at least a 50 percent reduction in $CO_2$ emissions from electricity generation by 2030 compared to 2005 levels (a more aggressive target than our most recent 40 percent by 2030 goal).

We've also added a longer-term goal of achieving net-zero carbon emissions from electricity generation by 2050. Our goal to attain a net-zero carbon future represents one of the most significant planned reductions in $CO_2$ emissions in the U.S. power sector. It is also consistent with the scientifically based range of both 1.5 and 2 degrees Celsius pathways, as


Exhibit TF-3



discussed in the sidebar on page 30. Implementing this bold vision requires us to begin planning and executing now. The choices and investments we make near term will be foundational to achieving net zero by midcentury. Continuing to modernize our fleet and grid at a measured pace will help protect customers from dramatic price increases. At the same time, we must pursue innovation by advocating for sustained investments in low- and zero-carbon technologies for this vision to become reality.

## Charting the Path

Achieving our carbon reduction goals will require at least five elements. We will continue to:

- **Collaborate and align with our states and stakeholders as we transform.** The steps and timeline for this transition will be unique in each state we serve, and we'll collaborate with customers, communities, policymakers and other stakeholders to determine the best path.
- **Accelerate our transition to cleaner energy solutions.** We're planning to at least double our portfolio of solar, wind and other non-hydroelectric renewables by 2025. We'll continue to need dispatchable, load-following, low-cost natural gas to speed the transition from coal and maintain affordability and reliability. New natural gas infrastructure will be required to fuel this transition and balance renewables. We'll continue expanding energy storage, energy efficiency, as well as electric vehicle infrastructure to support decarbonization of the transportation sector, now the largest $CO_2$-emitting sector.
- **Continue to operate our existing carbon-free technologies, including nuclear and renewables.** Our nuclear fleet's nearly 11,000 MW of carbon-free generation in the Carolinas – enough to serve nearly 7 million homes – is central to our ability to meet these goals. In September 2019, we announced that we will seek to renew the operating licenses of the 11 reactors we operate at six nuclear stations for an additional 20 years, which will extend their operating lives to and beyond midcentury.
- **Modernize our electric grid.** The company is investing in a multiyear effort to create a smarter and more resilient grid that can protect against extreme weather and cyber or physical attacks. These grid improvements also support adding more renewables while avoiding outages and providing customers more control over their energy use.
- **Advocate for sound public policy that advances technology and innovation.** This includes advanced renewable energy, longer-duration (up to seasonal) storage, new nuclear technologies, low- and zero-carbon fuels and effective ways to capture carbon emissions. The company will also support permitting reforms that will enable the deployment of new technologies and construction of critical infrastructure, both needed to address climate change.

As we partner with customers, policymakers, regulators and stakeholders in our respective states to make our transition, our integrated resource plans, financial plans and other regulatory filings will progressively reflect our proposed path (in accordance with the time frames mandated for each).



Exhibit TF-3


For example, Duke Energy has already retired 51 coal units totaling more than 6,500 MW since 2010, and we plan to retire an additional 900 MW by the end of 2024. In rate cases filed in 2019, we proposed to shorten the book lives of another approximately 7,700 MW of coal capacity in North Carolina and Indiana. We are also converting three of our largest coal plants in the Carolinas to run partially or fully on natural gas, providing resiliency and reducing carbon emissions. We recognize the importance of our power plants to the communities that host them and the workforce that operates them. As we retire coal plants, we will continue to strive to transition impacted employees to new opportunities and will work to match communities with appropriate resources.

### Taking a Comprehensive Approach

Addressing the complex challenge of climate change requires more than just carbon emissions reductions. Our holistic approach to addressing physical and transition (policy and economic) risks associated with climate change includes three key areas of focus: adaptation, mitigation and innovation.

- Adaptation – Duke Energy is taking steps to prepare for the changing global climate, including water conservation and storm preparation.
- Mitigation – We are working to slow climate change with a variety of carbon reduction and land conservation efforts.
- Innovation – Duke Energy is helping drive the new technologies necessary for a net-zero carbon future.

## Risk Management

### Our Approach

Climate change risks – including physical and transition (policy and economic) risks – are included in the company's Enterprise Risk Management (ERM) process. The ERM process is used to identify, assess, quantify and respond to a comprehensive set of risks in an integrated and informed fashion. ERM provides a framework to manage risks while achieving strategic and operational objectives and continuing to meet the energy needs of our customers.

Duke Energy performs a comprehensive enterprise risk assessment on an annual basis to identify potential major risks to corporate profitability and value, including risks related to climate change. To inform the annual risk assessment, the ERM group works with subject matter experts to identify and characterize key risks, including climate- and environmental-related risks. In addition, our chief risk officer meets with business unit leadership to discuss risks on a quarterly or semi-annual basis. The ERM group shares the annual enterprise risk assessment with the Board and reports regularly to the Finance and Risk Management Committee.

To assure Duke Energy is incorporating climate, technology and economic risks into our long-term planning, we annually, biennially or triennially (depending on the state) prepare forward-looking integrated resource plans (IRPs), or similar regulatory filings, for each of our regulated electric utility companies. These 10- or 20-year plans help us



Exhibit TF-3

evaluate a range of options, considering forecasts of potential future climate policies, future electricity demand, fuel prices, transmission improvements, new generating capacity, integration of renewables, energy storage, energy efficiency and demand-response initiatives.

In recognition of the increasing role of distributed energy resources, the company is expanding its planning and is developing new Integrated Systems and Operations Planning (ISOP) tools that will inform and evolve the current IRP process. This effort will significantly enhance the coordination of modeling and analysis across generation, transmissions, distribution and customer program planning functions. ISOP is motivated by the expectation that advancements in technology and declining costs will make non-traditional solutions such as energy storage increasingly competitive relative to traditional resources. ISOP will include enhancements to modeling processes necessary to accommodate renewable growth and value new technologies, such as energy storage, electric vehicles and advanced customer programs. In the areas of distribution planning, ISOP builds on our objective of enabling higher levels of distributed energy resources by developing planning tools that can fully leverage the intelligent grid control capabilities of our grid modernization efforts.

## Physical Risks

Extreme weather events – including hurricanes, heavy rainfall, more frequent flooding and droughts – can impact our assets, electric grid and reliability. Due to the location of some of our service territories, we must be especially vigilant about adapting to these risks.

### Storms and Heavy Rainfall Events

We are making strategic improvements to make the power grid more resistant to outages from severe weather and flooding, and adding new technologies that make the grid more resilient:

- Upgrading utility poles and power lines to make them more resistant to power outages and able to withstand higher winds and more extreme conditions.
- Using data to identify the most outage-prone lines on our system and placing those lines underground. In Florida, we recently announced a ten-year plan to underground and make other improvements to power lines that run through heavily-vegetated areas, and have stated a goal of either undergrounding or hardening all feeders and laterals by 2050. We are also upgrading underground routes to allow for more remote restoration opportunities.
- Installing a smart-thinking grid that can automatically detect power outages and quickly reroute power to other lines to restore power faster than ever. In 2019, self-healing technologies prevented more than 600,000 extended outages across the company's six-state electric service area and saved customers more than 1 million hours of total outage time.

We have developed mitigation measures that are being installed to keep substations better protected and in operation during severe storms. These measures include:

- Improved barriers that better withstand flooding to keep these essential systems operating.
- Targeted relocation of equipment – while barriers are usually the most effective solution, in some instances we will relocate equipment to nearby property that is outside the area prone to flooding.
- Remote communication, monitoring and restoration capabilities – we are installing new technology to monitor the health of key systems in substations, as well as self-healing capabilities that can help to reduce the number of customers impacted by a substation outage, even if crews are not able to physically reach the substation.

We have made improvements at our power plants to ensure they are capable of withstanding heavy rainfall events and flooding. For plants near the coast, these actions also help protect against potential sea level rise impacts:

- Raised the foundation of the new Citrus Combined Cycle Station in Florida to protect the station from hurricane storm surges.
- Increased structural hardening and improved equipment protection at the Brunswick Nuclear Station in North Carolina to better resist flood impacts.



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- Evaluated and prioritized our fossil sites for possible flood risks and performed detailed modeling of the top four sites against 100- and 500-year storms and riverine flooding; additionally, updated our site-specific natural disaster preparation procedures.

In addition to our extensive mutual assistance partnerships with other utilities and contractors to bring additional resources in quickly to support our crews responding to major outage events, we have also improved our storm preparation and response capabilities:

- Improved storm and damage forecasting capabilities enable us to stay ahead of the storm, identifying likely areas of impact and moving resources into place ahead of the storm to respond faster.
- The use of drones to better assess damage and support crews in the field.
- Improved communication and control capabilities to give crews in the field more information and assistance when they need it.
- Improved customer communication tools to help keep customers informed about outage response and estimated times of restoration.

### Water Availability

Many sources of electricity require significant amounts of water for cooling purposes.
A prolonged drought could therefore risk reliable electricity generation.

Several of Duke Energy's fossil and nuclear power plants in the Carolinas are located on hydroelectric reservoirs that the company operates. Of course, water availability is an important consideration in those watersheds, both to Duke Energy and to others. In these areas, we collaborate with local water utilities, environmental groups and recreation enthusiasts on watershed and drought planning. Our hydroelectric projects also have drought response plans (known as "low inflow protocols" (LIPs)) embedded in their Federal Energy Regulatory Commission (FERC) operating permits; the LIPs work to conserve water in the reservoirs and protect all water intakes in the watershed, including those for Duke Energy's facilities, until it rains again. Duke Energy's hydroelectric projects also have procedures in place for managing operating conditions during "high inflow" (high rainfall) events.

Except for emergency situations, Duke Energy endeavors to maintain lake levels within the ranges set forth in its FERC licenses under normal operating conditions. Lake levels are closely monitored, and operational adjustments are made based on various factors, including weather forecasts.

Other Duke Energy facilities are protected from drought because they have closed-cycle cooling and/or operate on large sources of water or on cooling reservoirs; one (the Brunswick Nuclear Station) withdraws water from an estuarine environment and so is not susceptible to drought-related risks. We have also implemented equipment and operational changes at nuclear and coal plants to reduce potential drought-related risks.



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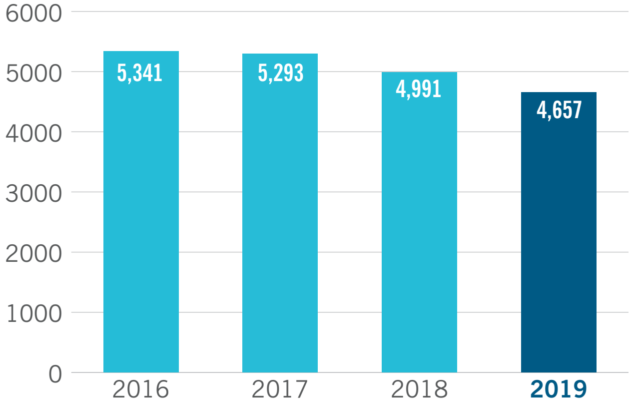
In 2018, we adopted a new goal to reduce annual water withdrawals by our generation fleet by 1 trillion gallons from the 2016 level by 2030.

Water Withdrawn for Electric Generation (billion gallons)




Our transition to cleaner energy by replacing coal and natural gas plants that use once-through cooling systems with natural gas combined-cycle plants that use closed-cycle cooling systems, and with renewables, reduces the amount of water withdrawn and thereby reduces the risk to operations from potential future droughts.

## Ash Management Program

Duke Energy has instituted a comprehensive ash management program that ensures that waste facilities, which are typically located at generating stations near waterbodies for cooling water, operate properly even in extreme weather. Scientific studies of our ash basins and landfills, dam safety inspections, emergency planning, ongoing environmental monitoring efforts and more – performed by the company and independent experts – address the operational, environmental, strategic and financial risks associated with effectively managing coal ash today and for decades to come.

Permanently closing ash basins is the most effective step we can take to address climate risk. The scope, scale and speed of the company's work to close basins make us an industry leader. Under our comprehensive ash management plan, we have:

- Completed extensive ash basin and cooling pond dam improvements across our fleet, which have enhanced dam safety and provide greater protection from severe weather.
- Stopped all flows into ash basins as part of the coal ash basin closure process (except at the Gallagher plant, which will retire in 2022), and the basins are being dewatered. This and other closure preparations have dropped the level of water in the basins significantly, creating space to accommodate significant rainfall.
- Excavated nearly 28 million tons of ash enterprisewide since basin closure began, with more than 5 million tons moved in 2019 alone. We have completed excavation of the basins at our Dan River, Sutton and Riverbend stations. As announced in January 2020, Duke Energy, state regulators and community groups agreed to a plan to permanently close the company's remaining coal ash basins in North Carolina primarily by excavation.

We are also utilizing operational experience and best practices from across the industry to modify and improve our facilities.

- Prior to severe weather, the company takes several steps to prepare for potential ash basin response, including pre-staging equipment and trained professionals, actively reducing water levels if needed and placing construction materials on-site to respond quickly if repairs are necessary.
- At the retired Sutton Plant in Wilmington, a special synthetic turf rated to withstand hurricane-force winds is being used to cap each landfill cell because it provides additional protection against erosion and strong winds that occur in the region.
- We've expanded or built new emergency spillways at cooling ponds at three facilities near the coast (H.F. Lee, Weatherspoon and Sutton) to safely move water through the system if necessary in order to prevent damage to the facilities. The company has robust emergency action plans for each facility covering ash basins and certain dams, which detail specific protocols to address a variety of situations, including severe weather events. These plans are reviewed annually with emergency managers and first responders, shared with regulators and updated as needed.





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## Policy Risks

Federal or state policies could be enacted to put a legal constraint on power plant emissions, add a price on carbon or mandate certain energy mixes. Other policies may be needed to enable our net-zero transition, such as those to facilitate the siting and cost recovery of needed transmission and distribution upgrades.

Since the publication of our 2017 Climate Report, the U.S. Environmental Protection Agency repealed the 2015 Clean Power Plan and finalized its replacement, the Affordable Clean Energy (ACE) rule. States will determine how the rule will be implemented, so we will better understand any potential impacts to our system once states finalize their plans over the next two years.

In addition, several bills have been introduced in the 116th Congress that seek to establish a price on $CO_2$ emissions, and House Energy and Commerce Committee leadership has introduced the Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act. This draft legislation includes a mandate to transition to 100 percent clean electricity by 2050. Other legislative approaches provide substantial support for the development of technologies needed for the net-zero transition, such as the American Energy Innovation Act. It is unclear when or if any of these proposals will be enacted by Congress.

Federal policymakers could also impose mandates that restrict the availability of fuels or generation technologies – such as natural gas or nuclear power – that enable Duke Energy to reduce its carbon emissions.

At the state level, the North Carolina governor recently directed the development of a state Clean Energy Plan that proposes to explore a variety of policies and actions that will seek to reduce carbon emissions, modernize the utility regulatory model and advance clean energy economic development opportunities. The North Carolina Clean Energy Plan calls for a 70 percent reduction in greenhouse gas emissions in the power sector by 2030 and aims to achieve carbon neutrality by 2050. Duke Energy is actively participating in the stakeholder process to inform and shape the final policy proposal. The stakeholder process is currently slated to provide recommendations to the governor by year-end 2020. It is likely that proposals generated through the process would require legislative or regulatory action to be adopted.

In Indiana, legislation was enacted in 2019 that established a 21st Century Energy Policy Development Task Force. The task force is comprised of members of the House and Senate as well as gubernatorial appointees representing various energy-related stakeholders. The statute requires the Indiana Utility Regulatory Commission (IURC) to examine Indiana's future energy resource needs; existing policies regulating electric generation portfolios; how shifts in electric generation could impact reliability, resilience and affordability; and whether state regulators have appropriate authority regarding these matters. This report is due in July 2020. The IURC has a contract with Indiana University for a second study, not required by statute, to examine the impact



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of plant closures on local communities. The task force's recommendations are due to be reported to the General Assembly and the governor by December 2020.

Duke Energy has long advocated for climate change policies that will result in reductions in $CO_2$ emissions at reasonable costs over time. We support market-based approaches that balance environmental protection with affordability, reliability and economic vitality.

## Duke Energy's View on Effective Carbon Policy

It's our view that effective policies to reduce $CO_2$ emissions should include these principles:

- Cost-effective
- Market-based
- Equitable
- Provisions for all emitting sectors
- Environmentally effective
- Promotes technology development
- Politically sustainable

While it is unclear what specific policies will receive formal consideration in Congress, our analyses have identified some key policy attributes that we believe will allow us to achieve our net-zero goal while allowing us to maintain lower costs for our customers. These attributes will also help to incentivize the adoption of new, low- and zero-emitting technologies. Therefore, we believe climate policy should:

- Incentivize a zero-carbon trajectory at the lowest cost, rather than simply imposing a price or dictating a certain generation mix.
- Recognize that nuclear and natural gas generation remain essential to transitioning to an affordable and reliable net-zero carbon future.
- Recognize that regardless of whether (and which) market-based mechanism is adopted, robust and sustained support for research, development, demonstration and deployment of advanced technologies is critical.

Duke Energy factors policy risk into our strategies by evaluating carbon price scenarios in the development of our integrated resource plans. Since 2010, Duke Energy has included a price on $CO_2$ emissions in our IRP planning process to account for potential climate legislation or regulation. Incorporating a price on $CO_2$ in our IRPs allows us to evaluate existing and future resource needs against a potential climate change policy risk in the absence of policy certainty. We use a range of potential $CO_2$ prices (including no $CO_2$ price) to reflect a range of possible policy outcomes.

Other policies may be needed to enable our zero-carbon transition. For example, without streamlined permitting of transmission and distribution, the



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buildout of large volumes of renewables and energy storage will be a greater challenge.

## Economic Risks

Our continued efforts to drive carbon out of our regulated electric utilities' operations help mitigate Duke Energy's financial exposure to potential future climate legislation or regulation. However, potential regulations or legislation to address climate change may require Duke Energy's regulated electric utilities to make additional capital investments to comply and could increase operating and maintenance costs. (Our commercial unit, Duke Energy Renewables, is already 100 percent carbon-free.) As with costs incurred for complying with other types of environmental regulations, our regulated electric utilities would plan to seek cost recovery for investments related to carbon reduction through regulatory rate structures.

To mitigate the risk of stranded assets, we will engage with regulators – and with stakeholders – prior to retiring existing assets or making investments in new generating capacity. This robust regulatory approach supports our future ability to recover costs as we position our fleet for the transition to lower carbon emissions.

Another area of economic risk for our strategy is technology risk. As noted earlier, a critical part of our net-zero carbon strategy is the need for new technologies that are not yet commercially available or are unproven at utility scale. If these technologies are not developed or are not available at reasonable prices, or if we invest in early-stage technologies that are then supplanted by technological breakthroughs, Duke Energy's ability to achieve a net-zero target by 2050 at a cost-effective price could be at risk.

To reduce this risk, we are investing in new technology research, including the Electric Power Research Institute/Gas Technology Institute's Low Carbon Resource Initiative, which is a five-year effort to accelerate the development and demonstration of technologies to achieve deep decarbonization.

We also support policies to increase technology research, development, demonstration and deployment at the federal level. For example, Duke Energy has supported, on its own and through trade associations, including the Edison Electric Institute and the Nuclear Energy Institute, a package of technology-promoting legislation in the 116th Congress.[10] We are also a founding member of EEI's Clean Energy Technology Innovation Initiative, which is partnering with several NGOs, including Clean Air Task Force, the Center for Climate and Energy Solutions, and the Bipartisan Policy Center, to identify areas for advocacy on advanced technologies.

As we deploy increasing amounts of renewables, siting risk becomes a consideration – both for the renewables themselves and for the transmission infrastructure needed to enable the energy generated to travel to load centers. This could force Duke Energy to adopt more expensive or less optimal (from an operational standpoint) options.

Climate policies or activities to mitigate physical risks can add material costs to the price of electricity and customer bills. This could in turn affect projected electricity utilization increases (such as from growth in demand and electrification of other sectors), as well as Duke Energy's most vulnerable customers.

Another area of economic risks is risks related to insurance. Property insurance companies have said publicly that they intend to stop providing insurance to companies that have above a certain amount of coal generation, or have said that they will only provide coverage if a company has a plan to decrease that over a reasonable period of time.[11] As noted above, Duke Energy has retired significant amounts of coal capacity and has plans to retire more. The below discussion of our strategy to meet our net-zero $CO_2$ emissions goal shows that coal will be phased out of our generation fleet.

## Opportunities

Duke Energy is focused on the challenges climate change presents. We stand ready to meet those challenges while also recognizing concern about climate change can mean opportunities for our regulated electric utilities to make investments in renewables, energy efficiency, energy storage,

[10] See October 3, 2019, letter from Edison Electric Institute, the Nuclear Energy Institute and 26 other trade organizations to leaders McConnell and Schumer supporting a package of seven technology-promoting bills; October 15, 2019, letter to Speaker Pelosi and leaders McCarthy, McConnell and Schumer from Duke Energy and 24 organizations and companies supporting the Nuclear Energy Leadership Act; and March 2, 2020, letter from EEI, NEI, the U.S. Chamber of Commerce and 36 other organizations supporting the S. 2657, the American Energy Innovation Act.

[11] See, for example, "Liberty Mutual to Limit Coal Underwriting, Investments; Names First Sustainability Officer," Insurance Journal, December 16, 2019.



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grid modernization, as well as in electric vehicle infrastructure. Duke Energy's commercial renewables business can benefit from increased interest in renewables throughout the country. And new technologies to reduce emissions represent both a risk and an opportunity.

### Renewable Energy

Customer demand for electricity from renewable sources has increased due, in part, to concerns about climate change. Duke Energy has responded with initiatives in both its regulated and commercial renewables businesses and will continue to seek additional opportunities. In addition, regulatory or legislative policies related to climate change can prove to be a driver for opportunities for increased deployment of renewable generation sources.

Our commercial renewables business, Duke Energy Renewables, operates wind and solar generation facilities across the U.S., with a total electric capacity of approximately 4,000 MW. The power produced from commercial renewable generation is primarily sold through long-term contracts to utilities, electric cooperatives, municipalities, and commercial and industrial customers. Our five-year capital plan, rolled out in February 2020, included a $2 billion investment, net of tax equity financings, and we plan to continue to invest in this business beyond the next five years.

Opportunities for increased renewable energy also benefit our regulated generation business, where we have installed and are operating approximately 460 MW of solar and anticipate at least 660 MW to be added in the next three years. We also purchase substantial amounts of renewable energy in the form of long-term purchased power contracts, backed by the strength of our balance sheet. These purchases totaled nearly 4,000 MW at the end of 2019, and we are projected to add nearly 2,300 MW in the next three years.

Policies have also been approved in several of our states to encourage increased use of renewable energy, including, for example, our Green Source Advantage program for renewable energy in North Carolina (to which the city of Charlotte has signed on) and the Renewable Energy Credit (REC) Solutions programs in several of our regulated jurisdictions (in the latter, we work with large customers to procure RECs to meet their renewables needs).

### Energy Efficiency

Some of the most effective carbon reductions we can make involve helping customers avoid energy usage in the first place. Again, regulatory or legislative policies related to climate change can prove to be a driver for opportunities for increased deployment of energy efficiency. These opportunities are available for both our regulated and commercial businesses.

Our Carolinas utilities rank first in the Southeast in energy efficiency.[12] Our overall energy efficiency initiatives have helped customers in our regulated jurisdictions reduce energy consumption and peak demand by nearly 19,000 gigawatt-hours and 6,700 MW, respectively, since 2008. This cumulative reduction in consumption is more than the annual usage of 1.58 million homes, and the peak demand reduction is equivalent to more than 10 power plants each producing 600 MW. Learn more about energy efficiency.

### Energy Storage

Battery storage and microgrids are key technologies that can help better integrate solar into the grid while, among other uses, improving customer reliability and grid security, as well as reducing economic impacts to customers through the ISOP framework described above. Duke Energy plans to invest roughly $600 million over the next five to 10 years to expand battery storage by almost 400 MW. The company also has more than 2,000 MW of pumped storage hydro power, another energy storage method that can provide long-term storage. We plan to install upgrades at our Bad Creek pumped storage hydro facility in South Carolina to increase its capacity by more than 300 MW.

### Grid Modernization and Infrastructure Expansion

Climate change presents opportunities for Duke Energy to continue to modernize its grid to benefit customers both for resilience against the physical risks from climate change and for increased utilization of renewables. This opportunity can mean increased investments in both transmission and distribution assets, as well as in energy storage, as discussed above.

[12] Southern Alliance for Clean Energy, "Energy Efficiency in the Southeast: 2019 Annual Report," January 2020, https://cleanenergy.org/blog/energy-efficiency-in-the-southeast-2019-annual-report/.



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Smart meters are just one example of how Duke Energy is working to modernize the grid for the benefit of our customers. Duke Energy has installed smart electric meters for more than 80 percent of its customers. With these meters, and time-of-use rates, customers can plan their energy use so that they can save energy and money. Time-of-use rates encourage customers to use energy when demand is lower, which can make energy more affordable for customers while helping the company maintain reliability during peak periods. The company is currently piloting several new time-of-use rates in North Carolina and has proposed several variations of pilot programs in Indiana. These pilots are designed to work in conjunction with newly-installed smart meters to provide price signals at times of peak demand to customers. The pilots will allow the company to develop new, cutting-edge rate designs that will work with renewables and electric vehicles.

## Electric Vehicles

Part of our contribution to reducing overall greenhouse gas emissions also involves helping lower emissions from the transportation sector. We've proposed a bold $76 million initiative in North Carolina, to date the largest investment in electric vehicle infrastructure in the Southeast. This will include nearly 2,500 new charging stations that will lead to a statewide network of fast-charging stations and will help fund the adoption of electric school buses and electric public transportation. Similar pilot programs are being considered by regulators in South Carolina ($10 million), Indiana ($10 million), Ohio ($16 million) and Kentucky ($3 million). We also expect to have installed more than 500 charging stations in Florida by 2022. Duke Energy is also adopting electric vehicles into its fleet, having acquired roughly 600 vehicles thus far. Learn more about the benefits of electric vehicles.

## New Technologies

To get to net-zero carbon emissions, while keeping energy affordable and reliable, new technologies that are economically competitive at commercial scale are necessary. Technologies such as CCUS, longer-duration (up to seasonal) energy storage, new nuclear technologies, and yet-to-be-imagined discoveries, as well as innovative use of greener fuels such as renewable natural gas and hydrogen will be important. To take advantage of these opportunities, we are supporting policies that will advance new technologies and investing in research and development for these important innovations, as discussed on page 5.



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# Metrics and Targets

Greenhouse gases (GHG) emitted by Duke Energy facilities include carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$) and sulfur hexafluoride ($SF_6$). The burning of fossil fuels to generate electricity is by far the primary source of Duke Energy's GHG emissions, producing emissions of $CO_2$, $CH_4$ and $N_2O$. The other sources of Duke Energy GHG emissions include $CH_4$ emissions from natural gas distribution operations, and emissions of $SF_6$, an insulating gas used in high-voltage electric transmission and distribution switchgear equipment.

As of year-end 2019, Duke Energy has reduced $CO_2$ emissions 39 percent from electricity generation since 2005, ahead of the industry average of 33 percent.[13] In 2019, we accelerated our carbon reduction goal from 40 percent to more than 50 percent by 2030. We also added a longer-term goal of achieving net-zero carbon emissions by 2050. Progress toward our $CO_2$ and other sustainability goals will continue to be updated on an annual basis in our Sustainability Report.

In the following tables, we adhere to the World Resources Institute/World Business Council for Sustainable Development Greenhouse Gas Corporate Protocol Standard, which classifies a company's GHG emissions into three "scopes." Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy (that is consumed by the reporting company). Scope 3 emissions are all indirect emissions (not included in Scope 2) that occur in the value chain of the reporting company.[14]

## Scope 1 Emissions

### Greenhouse Gas Emissions from Electricity Generation (thousand short tons $CO_2$ equivalent ($CO_2e$))

| | 2005 | 2017 | 2018 | 2019 | 2030 Goal | 2050 Goal |
|---|---|---|---|---|---|---|
| $CO_2$ | 153,000 | 105,000 | 105,000 | 93,000 | 76,500 *(At least 50% below 2005)* | Net-zero |
| $CH_4$[15] | 420 | 230 | 218 | 186 | – | – |
| $N_2O$[16] | 731 | 391 | 369 | 361 | – | – |

All data based on ownership share of generating assets as of December 31, 2019.

### Methane Emissions from Natural Gas Distribution (thousand short tons $CO_2e$)

| | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|
| $CH_4$ | 184 | 175 | 176 | 185 |

### Sulfur Hexafluoride Emissions from Electric Transmission and Distribution (thousand short tons $CO_2e$)

| | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|
| $SF_6$ | 573 | 536 | 337 | 535 |

$SF_6$ emissions fluctuations are due to maintenance, replacement and storm repair needs.

[13] U.S. Energy Information Administration, *Monthly Energy Review*, March 26, 2020.
[14] See https://ghgprotocol.org/sites/default/files/standards_supporting/FAQ.pdf.
[15] No goal is established for methane emissions from electricity generation – see methane sidebar.
[16] No goal is established for $N_2O$ emissions from electricity generation; emissions of this gas will decline with reductions in fossil fuel use.



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## Reducing Methane Emissions

Duke Energy has been an industry leader in driving down methane emissions. Since 2001, Duke Energy's Piedmont Natural Gas unit has been a member of EPA's Natural Gas STAR program, which emphasizes best management practices to voluntarily reduce methane emissions and report those reductions. In 2016, all of Duke Energy's gas operations became founding members of EPA's Methane Challenge.

Duke Energy is also monitoring, through its memberships in the Edison Electric Institute (EEI) and the American Gas Association (AGA), the development of the EEI/AGA Natural Gas Sustainability Initiative (NGSI), an initiative that focuses on the measurement and disclosure of methane emissions throughout the entire natural gas supply chain.

To reduce methane emissions and improve the safety and reliability of the natural gas system in Ohio and Kentucky, Duke Energy implemented the Accelerated Main Replacement Program (AMRP) in 2000. The program's purpose was to replace cast iron and bare steel pipelines (and associated services) with plastic or coated steel pipe.[17] The program was completed in Kentucky in 2010 and in Ohio in 2015. Piedmont Natural Gas had already completed a similar program when it merged with Duke Energy in 2016. We also recently completed an accelerated service line replacement program in Kentucky in which approximately 30,000 service lines were replaced. In total, Duke Energy's Natural Gas Business Unit has replaced 1,454 miles of cast iron pipe on its distribution system with either plastic or cathodically protected steel.

It should be noted that the methane emissions we report above (a total of less than half of one percent (0.5%) of our $CO_2$ emissions from electricity generation, on a $CO_2$ equivalent basis) are, as required by EPA, based on EPA emissions factors. For emissions from electricity generation, EPA emission factors are applied to the amounts of the various fossil fuels we combust. For emissions from our natural gas distribution system, methane emissions are calculated by applying EPA emission factors (for different pipe materials) to the miles of natural gas pipelines we operate, and to the number of services. We also quantify leaks based on leak survey data. Given this, as our natural gas distribution system expands, emissions (all other things being equal) will tend to increase. We are carefully evaluating our sources of methane emissions and potential avenues to reduce them further.

[17] In natural gas parlance, "service" means the service pipe that carries gas from the main pipe to the customer's meter.

## Scope 2 and 3 Emissions

In 2019, Duke Energy reported to CDP (formerly known as the Carbon Disclosure Project) 25,600 tons of Scope 2 $CO_2$ equivalent emissions for 2018. These are estimated from power purchases for Duke Energy facilities that are not served by Duke Energy itself.

In 2019, Duke Energy reported to CDP the following categories of Scope 3 $CO_2$ equivalent emissions for 2018:

| Category | Thousand short tons $CO_2e$ |
|---|---|
| **Fuel and energy-related activities (not reported in Scope 1 or 2).** This is an estimate of $CO_2$ emissions associated with electricity Duke Energy purchased for resale. | 11,122 |
| **Use of sold products.** These are $CO_2$ emissions from the use of natural gas that Duke Energy delivers to its end-use customers. | 19,811 |


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# Net-Zero Scenario Analysis

The following analysis examines a scenario, including sensitivities, for achieving our net-zero $CO_2$ emissions goal by midcentury, along with the potential impacts on the generation portfolio of our regulated electric utilities. This analysis was conducted using the same industry-standard expansion planning and hourly production cost modeling tools that we use for integrated resource planning. The analysis, however, did not include transmission and distribution modeling that would be required to assess cost and technical feasibility of interconnecting such large quantities of renewables with operational feasibility.

**It should be emphasized that the scenario analysis presented is intended only to provide an enterprisewide directional illustration of the impact of changes in the generation fleet.** The results presented are indicative of potential options to meet Duke Energy's targets but **do not represent specific utility resource plans and will change over time as new information becomes available**. We will work collaboratively with stakeholders and regulators in the states we serve as we develop future resource plans pursuant to regulatory requirements.

## Key Assumptions and Considerations

Any analysis that goes out three decades includes numerous uncertainties and assumptions. Because it is based on currently available technology and cost information, the company's IRP process provides a relatively more certain view through 2030. Projecting beyond that time frame requires assumptions for how technology, electricity demand and costs may evolve several decades in the future. To follow the spirit of the IRP process in the modeling from 2030 to 2050, the technologies considered were limited to those in which we have reasonably high confidence in their likely commercial availability and in current projections of their costs. With those caveats, our net-zero scenario analysis makes the following assumptions:



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| NET-ZERO SCENARIO ASSUMPTIONS | |
|---|---|
| **System Load** | Average annual increase of 0.46 percent from 2020 to 2050. This is based on an EPRI study done for the Carolinas that assumes significant adoption of energy efficiency measures in buildings and industry, resulting in flat electricity demand through 2050 (offsetting all load growth due to new customers).[18] On top of this, the study assumes significant transportation electrification, resulting in the 0.46 percent per year load growth we assume here. While this study was done for the Carolinas, similar adjustments in the load forecast were applied to all our jurisdictions. |
| **Existing Nuclear** | All existing nuclear capacity is relicensed and authorized to operate for an additional 20 years (for a total operating life of 80 years). Existing nuclear generation is assumed to be capable of reducing output by up to 20 percent to aid in balancing generation and load. |
| **Accelerated Coal Retirements** | All coal units in the Carolinas, except those that have been or are being modified to run fully or partially on natural gas, are retired by 2030. All remaining coal units except the Edwardsport Integrated Gasification Combined Cycle plant are retired by 2040. Edwardsport is retired by 2045. For the net-zero carbon scenario, Cliffside 6 was assumed to operate exclusively on natural gas by 2030, until its retirement in 2048. Note that these are modeling assumptions and do not necessarily match retirement dates filed in regulatory proceedings. Future resource plans will be developed working collaboratively with stakeholders and regulators in the states we serve, pursuant to regulatory requirements. |
| **Natural Gas Assets** | To test the economics of the model, all natural gas combined-cycle units built in the 2020s are assumed to have a 20-year book life. Beyond 2030, all natural gas additions are assumed to be combustion turbines (“peakers”) only. We also explored a sensitivity where no new natural gas electricity generation was added. |
| **Markets** | No market Regional Transmission Organization energy purchases or purchased power agreements are assumed beyond 2035 due to the uncertainties of how the markets and other utilities’ resource plans will evolve that far into the future. This is a conservative approach to ensure that customer load is served. Actual plans would consider market purchases if they were the most economical. |
| **Fuel Prices** | Coal prices are projected to continue to remain low into the future, but a slightly higher, though still relatively low, natural gas price trajectory in the near- to mid-term continues to support gas as baseload or intermediate generation ahead of coal. Nuclear prices remain low relative to both coal and gas and support continued operation of Duke Energy’s existing nuclear fleet. |

[18] Electric Power Research Institute, “North Carolina Efficient Electrification Study: Task 1 Energy System Assessment,” November 2019.



Exhibit TF-3

| | |
|---|---|
| **Technology Prices[19] (approximate overnight capital costs)** | ▪ Combustion Turbines – \$550/kilowatt (kW) (represents multi-unit site)<br>▪ Combined Cycle – \$650/kW (represents 2x1 advanced class)<br>▪ Small Modular Nuclear Reactor – \$5,500/kW<br>▪ Natural gas combined cycle (NGCC) with CCUS – \$2,000/kW (cost is at the fence line; cost to transport $CO_2$, which is highly dependent on location, as well as the cost of injection, would be additional)<br>▪ Solar – \$900/kW<br>▪ Wind – \$1,300/kW (on shore) to \$2,400/kW (offshore)<br>▪ Pumped storage hydro – \$2,500/kW (existing reservoirs)<br>▪ Lithium-ion storage – \$900/kW (4 hour) to \$1,600/kW (8 hour) – consistent with the NREL annual technology baseline and excludes allowance for degradation, limits of depth of discharge, and owners and interconnection costs<br>**NOTES:**<br>Interconnection costs for these technologies were not explicitly considered in the scenario analysis. This assumption yields an optimistic view of the costs of adding large quantities of renewables to the grid. Typical costs of transmission access for various types of renewables are shown below as a percentage of total project costs:<br>▪ Conventional generation – 10 percent (constrained area)<br>▪ Solar – 20 percent (bundled solar in constrained area)<br>▪ Wind (offshore and out of state) – 25-50 percent (location-dependent)<br>▪ Batteries – 20 percent (depends on location and primary use)<br>Transmission access cost is expected to increase with greater amounts of renewables and will be dependent on location, type, amount and existing infrastructure. Due to uncertainty in these factors, projections of future transmission access costs were not included. |

[19] These prices are in line with NREL's Annual Technology Baseline: https://atb.nrel.gov. Escalations are based on the Energy Information Administration's Annual Energy Outlook 2019.





Exhibit TF-3

| | |
|---|---|
| **Battery Storage** | Batteries are assumed to be available to store energy for four, six or eight hours. It is also assumed that there are no limitations on the supply chain for batteries and that they can be interconnected in a timely manner and without cost constraints. To ensure safe operation of batteries and account for degradation throughout the life of the assets, there is an assumed overbuild of batteries to provide the proper safety margin in the depth of discharge; this overbuild was incorporated in the analysis but was not reflected in the "technology prices" section above for purposes of comparability with publicly available information.<br><br>Seasonal battery storage and associated cost information is not currently available and its development is uncertain, so it is not assumed in the model. We view ongoing research into battery storage as vital to reducing costs and enabling longer-duration storage, but because the timing of technological breakthroughs for battery storage remains unclear (as do the costs of battery storage after the breakthroughs), we did not speculate on the timing or cost impact of a breakthrough in battery technology in this limited analysis. |
| **Technology Innovation** | ZELFRs are assumed to be commercially available for deployment in the mid-2030s. ZELFR is a generic placeholder in this modeling effort for a gap in commercially available utility-scale technology to complement very high penetration of renewables. ZELFRs must be flexible to respond to dynamic changes in both load and renewable generation, and must also be capable of sustained generation over long durations to handle severe weather events like "polar vortex" cold events and long-duration generation outages such as those that can occur after hurricanes.<br><br>For purposes of cost analysis, costs for ZELFRs were based on small modular nuclear reactors as the most feasible option given that 2027 is the expected commercial operation date for the first NuScale SMR reactor and that we have reasonable confidence in the current cost data. For an operational assessment (not based on cost), we also analyzed a generation mix that assumes ZELFRs are combined-cycle power plants that use natural gas, hydrogen or biofuels (such as renewable natural gas), with CCUS as appropriate. In reality, a combination of several technologies will likely be utilized. |

## Net-Zero Scenario Analysis Results

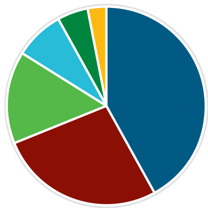
As discussed above, this analysis was conducted using the same industry-standard expansion planning and hourly production cost modeling tools that we use for integrated resource planning, and assumes normal weather. **It is important to note that the following results are solely illustrative and reflect only one of the possible generation mixes that would result in net-zero emissions by 2050.** We have projected ZELFRs in two ways: (1) with ZELFRs being relatively less-flexible resources, such as a small modular nuclear reactor (SMR), and (2) with ZELFRs being flexible and easily dispatchable (like a NGCC with CCUS). This analysis assumes ZELFRs are half SMRs and half NGCC with CCUS. (It should be noted that NGCC with CCS could also be biofuels or hydrogen.)

**These results do not represent definitive utility resource plans. Each utility's resource plan will be developed in conjunction with regulators, policymakers and stakeholders, and will require regulatory approval under our legal mandate to provide affordable and reliable energy.**

The following charts show the company's 2019 actual regulated electric utility capacity mix and potential 2030, 2040 and 2050 capacity mixes (in GW) under a net-zero carbon scenario analysis.

## Duke Energy Regulated Generating Capacity, GW

2019

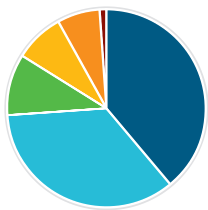


42% Gas (25 GW)
27% Coal (16 GW)
15% Existing Nuclear (9 GW)
8% Renewables* (5 GW)
5% Purchase/Sales (3 GW)
3% Storage (2 GW)

2030

49% Gas (36 GW)
20% Renewables* (15 GW)
12% Existing Nuclear (9 GW)
12% Coal (9 GW)
6% Storage (4 GW)
1% Purchase/Sales (1 GW)

2040



39% Gas (34 GW)
35% Renewables* (31 GW)
10% Existing Nuclear (9 GW)
8% Storage (7 GW)
7% ZELFRs (6 GW)
1% Coal (1 GW)

2050

44% Renewables* (47 GW)
23% Gas (24 GW)
12% Storage (13 GW)
12% ZELFRs (13 GW)
9% Existing Nuclear (9 GW)

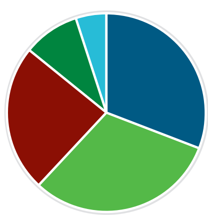
*Renewables include hydro, wind, solar, landfill gas, biomass, etc.

The following charts show the company's 2019 actual regulated electric utility generation (energy) mix and potential 2030, 2040 and 2050 generation mixes (megawatt-hours) under a net-zero carbon scenario analysis.

## Duke Energy Regulated Generation, MWh

2019

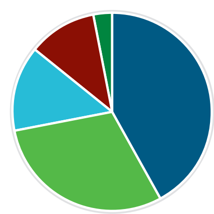
39% $CO_2$ Reduction



31% Gas
31% Existing Nuclear
24% Coal
9% Purchase/Sales
5% Renewables*

2030

52% $CO_2$ Reduction



42% Gas
30% Existing Nuclear
14% Renewables*
11% Coal
3% Purchase/Sales

2040

78% $CO_2$ Reduction

29% Renewables*
29% Existing Nuclear
25% Gas
16% ZELFRs
1% Coal

2050

95% $CO_2$ Reduction

36% Renewables*
30% ZELFRs
28% Existing Nuclear
6% Gas

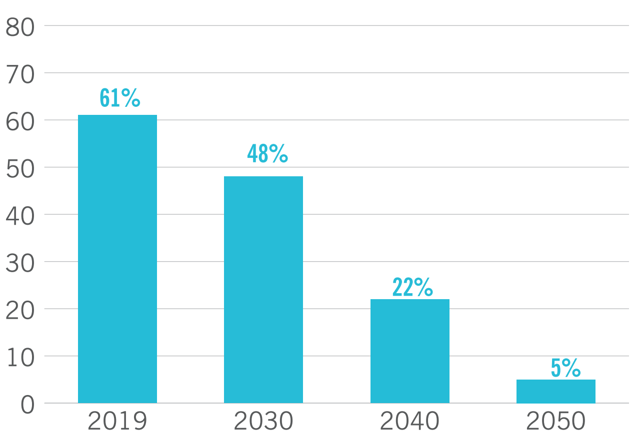
*Renewables include hydro, wind, solar, landfill gas, biomass, etc.



Exhibit TF-3

The following chart shows a projection of how Duke Energy's $CO_2$ emissions will decline as our electric generating fleet transforms.

Percent of 2005 $CO_2$ Emissions




## Key Insights

We are on track to achieve our 2030 goal of reducing $CO_2$ emissions from electricity generation by at least 50 percent from the 2005 baseline. The trajectory to make very deep reductions in $CO_2$ emissions by 2050 in line with our net-zero goal will depend on the availability of advanced low- and no-carbon technologies. Some emissions may be more cost-effectively addressed through the purchase of offsets; we project that would be about 8 million tons in 2050 (approximately 5 percent of our 2005 emissions).[20] Other key insights from the extensive modeling that was conducted to analyze this scenario include:

- **Renewables must be diversified and balanced with energy storage.** Renewables will play a key role in meeting the need for carbon-free energy. Diversity of renewables helps to reduce the need for storage, but even with a balanced portfolio of wind, solar and energy storage, further additions of renewables above a certain point – which varies among each of our modeled jurisdictions – have diminishing value and ultimately become uneconomic for carbon reduction. For example, for solar, this is due to the inability to shift the timing of renewable generation (which peaks midday) to match early- and late-hour peak energy demand. See page 29 for external studies that have reached a similar conclusion, including a study of the impacts of integrating increasing amounts of renewables into Duke Energy's Carolinas territories performed by the National Renewable Energy Laboratory.
- **Maintaining existing nuclear is critical.** Achieving net-zero $CO_2$ emissions by 2050 requires our existing nuclear fleet to be granted subsequent license renewals. The first Duke Energy nuclear power plants will approach the end of their current operating licenses in the early 2030s.

[20] Carbon offsets are the reduction of greenhouse gas emissions to the atmosphere. These can include modified agricultural practices, tree planting and reductions in other sectors. The market for carbon offsets decades in the future is very uncertain, but given its likely importance for the power sector and other large energy producers/users, we hope and believe that a robust market will emerge. We are monitoring negotiations under Article 6 of the Paris Agreement, where rules for carbon trading and the use of offsets will be developed.



Exhibit TF-3

- **ZELFRs will need to be installed by 2035.** In order to achieve our net-zero goal, ZELFRs are needed starting in 2035 to retire older fossil generation, maintain grid reliability and balance the intermittency of renewables.[21] These technologies need to be developed and refined over the next 10 years so that we can confidently plan to use these to serve our customers reliably while achieving net-zero carbon emissions. In the net-zero carbon scenario, ZELFRs make up 12 percent of capacity and supply 30 percent of energy due to their ability to operate at full output over extended periods regardless of weather conditions. The need for dispatchable net-zero carbon resources is driven by the fact that renewable resources are not well-correlated with the winter load shape that drives resource planning requirements for much of the Duke Energy fleet; in addition, the current cost and scale of energy storage technology makes backing up very large amounts of renewables with storage over long durations impractical. If ZELFRs become available and economically feasible prior to 2035, this would provide opportunities to accelerate coal retirements and achieve additional carbon reductions at a relatively low cost.

- **Unprecedented, sustained pace of capacity additions will be needed.** The net-zero carbon scenario requires Duke Energy to add new capacity at a rate double that achieved nationwide during the highest-growth decade in U.S. history, and more than double the rate at which Duke Energy added capacity over the past three decades. Moderate load growth combined with coal and gas retirements, along with the intermittency of renewables and the need for storage capacity, are key drivers for these unprecedented capacity additions. Replacing traditional electric generating capacity with renewables plus storage is not a one-for-one proposition. Due to the intermittency of renewables, significantly more capacity must be built, even with storage availability, to provide the same level of reliable electricity as a fossil plant.[22] This build rate will be challenging from many aspects, including permitting and regulatory approvals, labor, supply chain and interconnection needs.

- **Benefits of natural gas to facilitate the retirement of coal and balance renewables.** Natural gas continues to play a critical role in achieving our 2030 and 2050 carbon reduction goals. Deploying low-cost natural gas helps speed the transition from coal and balance the intermittent nature of renewables. Even in 2050, natural gas capacity needs to remain on the system to maintain reliability, especially during times of peak electricity demand. However, the mission of the gas fleet will change from supplying 24/7 power today to a peaking and demand-balancing function by 2050. This remaining gas generation is projected to represent 5 percent of 2005 emissions, netted to zero through carbon offset purchases.

We conducted a sensitivity analysis that assumed our regulated electric utilities are not allowed to build any additional natural gas generation. This constraint would make maintaining reliable and affordable electricity very challenging, while providing a modest 5 percent decrease in cumulative $CO_2$ emissions between 2020 and 2050.

This "no new gas" sensitivity presents significant challenges, some of which may be very difficult to overcome, including interconnection and operational and supply chain issues associated with unprecedented additions of energy storage over a very short period of time, as well as regulatory approvals, permitting, construction and greater costs to customers. For example, Duke Energy alone would need to add more than 15,000 MW of energy storage by 2030, more than 17 times the entire battery storage capacity (899 MW) of the entire United States today.[23] Our analysis shows that the incremental cost would be three to four times that of the net-zero scenario that includes gas, and would require the construction and operation of enormous amounts of renewables and energy storage. And this analysis

[21] This capacity is especially important in our Midwest and Florida jurisdictions as they do not currently have nuclear capacity.

[22] See, for example, University of North Carolina: "Measuring Renewable Energy as Baseload Power," March 2018. https://kenaninstitute.unc.edu/publication/measuring-renewable-energy-as-baseload-power/. To equal 1 MW of natural gas combined-cycle generation, the company would need to add 5 MW of solar with 4 MW of four-hour lithium-ion batteries. The true costs of renewables are therefore substantially higher than the levelized cost of electricity reported in many studies that do not include the cost of backup power.

[23] EIA, U.S. Utility-scale battery storage power capacity to grow substantially by 2023, July 2019. https://www.eia.gov/todayinenergy/detail.php?id=40072.



Exhibit TF-3

does not include the substantial transmission and distribution upgrade costs and permitting challenges necessary to enable the increased interconnection of energy storage and renewables. Aside from the implications of the cost impacts to our customers, especially low-income customers and energy-intensive businesses, the dependence of the "no new gas" sensitivity on a rapid addition of energy storage increases the possibility that existing resources would need to be relied upon for a longer time frame than anticipated.

Before considering the "no new gas" sensitivity as a serious alternative, it would be necessary to perform more extensive analysis to address the fact that production cost models have "perfect foresight" (with respect to weather, unplanned generation outages, etc.), while in the real world, operators do not know when such changes will occur and may not have the energy storage in the needed state (of charge or discharge) to manage actual conditions. Based on our historical experience with pumped-hydro energy storage, we understand that relying more heavily on renewables and limited-duration energy storage for capacity (the role dispatchable resources have traditionally played) will increase the complexity of planning and operating the system. Further, highly technical analysis is needed to ensure that the "perfect foresight" assumption is not masking potential system reliability challenges that would need to be addressed.

- **Focused efforts will be required to improve forecasting and portfolio balancing capabilities.** The challenges of balancing load with increasing levels of renewable generation will warrant exploration of opportunities to reduce renewable forecast error and improve our ability to react. Improving the accuracy of renewable generation forecasts will reduce the need for backup requirements (either storage or quickly ramping natural gas). Opportunities to improve forecast accuracy could include advanced sensing/ monitoring equipment as well as continued advancements in wind and irradiation forecasting techniques. In order to react more quickly, we are focused on improving the flexibility of our generation fleet, which can be achieved by installing more flexible and dispatchable resources; we are also reviewing potential market opportunities to better enable our grid to accommodate more intermittent, carbon-free resources. We are also exploring opportunities to add flexibility on the demand side through innovative customer programs and rate design.

## Third-Party Renewables Studies

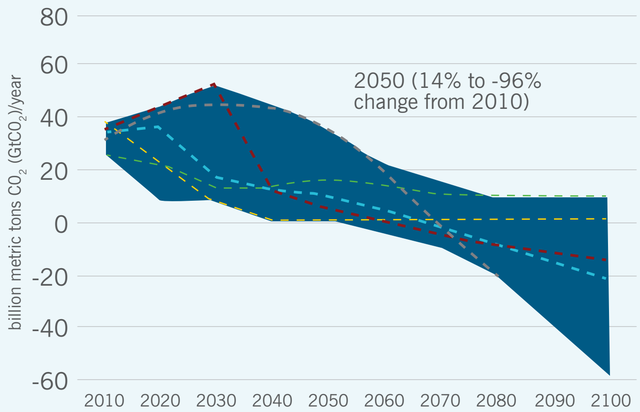
Several recent studies have examined the potential penetration of renewables in the power system. These studies, including one performed by DOE's National Renewable Energy Laboratory (NREL) of Duke Energy's Carolinas system, all conclude that further additions of renewables above 40%-50% of energy served have diminishing value and become increasingly uneconomic for carbon reduction. The studies also find that diversity of renewable resources (wind and solar) enables larger shares of carbon-free generation. Several of these studies are listed below.

- MIT: "Deep Decarbonization of the U.S. Electricity Sector: Is there a Role for Nuclear Power?" September 2019. https://globalchange.mit.edu/publication/17323
- NREL: "Duke Energy Carolinas and Progress: Zero-Emission Resource Integration Study," December 2019. www.nrel.gov/docs/fy20osti/74337.pdf
- MIT: "Storage Requirements and Costs of Shaping Renewable Energy Toward Grid Decarbonization," Joule, November 2019. https://www.sciencedirect.com/science/article/abs/pii/S2542435119303009.

## Duke Energy Carbon Reduction Goals and 1.5 and 2 Degree Celsius Global Emissions Scenarios

Many stakeholders are interested in companies' analyses of scenarios that will limit global average warming to 2 degrees Celsius or lower. To inform our view of scenarios and how these relate to our climate goals, Duke Energy has been engaged for nearly two years with the Electric Power Research Institute (EPRI) in a project evaluating scientific understanding of the relationship between company scenarios and global climate goals. The purpose of the project is to develop a strong technical foundation for company analysis and decision-making on scenarios and climate goals. Among other things, the project has assessed the relevant science through a number of studies and derived insights for companies and stakeholders.[24] We find, upon a review of EPRI's conclusions, that the scenario we analyze in this report to achieve our net-zero climate goal is consistent with scenarios limiting global average temperature increase to less than 2 degrees Celsius, and is also consistent with scenarios that limit global average temperature increase to less than 1.5 degrees Celsius.

The EPRI studies find, among other things, that there are many emissions pathways consistent with limiting warming to any particular global average temperature due to uncertainty about future economic conditions, technology advances, energy consumption, other emissions and elements that affect climate change, physical system dynamics, and policy action. For example, the figure above (figure ES-2 from EPRI's 2018 study) shows the range for 408 global emissions pathways derived from peer-reviewed literature that are consistent with limiting warming to less than 2 degrees Celsius.




Global net $CO_2$ emissions pathway range for pathways consistent with limiting global average temperature to less than 2C. Range for 408 scenarios (shaded area) and illustrative select scenarios (dotted lines) shown. Source: Rose and Scott (2018)

Similar to global economy-wide emissions outcomes, EPRI also concludes that "large ranges of global electricity carbon dioxide ($CO_2$) emissions pathways and budgets are consistent with limiting warming to 2°C." In addition, the EPRI studies find that the global and sectoral results provide only partial representations of uncertainty, with key uncertainties relevant to individual companies absent (e.g., uncertainty about policy design details and company-specific circumstances).

Importantly, the EPRI study goes on to compare this literature-derived range of pathways with single pathways used by the Science-Based Targets initiative (SBTi) and the United Nations Environment Programme's Finance Initiative.[25] The study concludes that while these single pathways lie within the ranges of the pathways described above, they do not capture the "uncertainty evident in the literature regarding global emissions pathways consistent with limiting warming to 2°C." The factors behind the different pathways are uncertainties relevant to companies and important to consider, in addition to the uncertainties absent (e.g., alternative policy designs).

[24] Rose, S.K., M. Scott, 2018. Grounding Decisions: *A Scientific Foundation for Companies Considering Global Climate Scenarios and Greenhouse Gas Goals*. EPRI. Palo Alto, CA. 3002014510; Rose, S.K., M. Scott, 2020. *Review of 1.5˚C and Other Newer Global Emissions Scenarios: Insights for Company and Financial Climate Low-Carbon Transition Risk Assessment and Greenhouse Gas Goal Setting*, EPRI, Palo Alto, CA. 3002018053.
[25] *Ibid* 2018, Appendix A.


Exhibit TF-3

Given that Duke Energy's net-zero by 2050 target is within the range of the scenarios shown in the EPRI analyses, the company believes that the scenario analyzed is consistent with limiting global warming to 2 degrees Celsius. Further, we believe the target is also consistent with limiting warming to 1.5 degrees Celsius according to EPRI's 2020 study. Note, however, that the EPRI analyses find that global scenarios have limited value as benchmarks for assessing company strategies for a variety of reasons, including that the aggregate scenarios do not represent the unique circumstances, uncertainties and risks relevant to individual companies. Furthermore, given that future markets, technology and policy are uncertain, as noted in the net-zero scenario analysis above, exactly how we will achieve our net-zero goal is uncertain; the analysis shown in this report is illustrative of pathways we might take.



## Looking Ahead

The actual pathway that Duke Energy takes to achieve net-zero carbon emissions by 2050 will be based on evolving technologies, costs, demand for electricity, public policy, stakeholder input and regulatory approvals. During the 2020s, significant innovation and technological advancement will be critical to ensure we have the viable technology options needed by the 2030s to achieve a net-zero carbon future by the 2050s. As we have done for more than a century, we will collaborate with regulators, policymakers and other stakeholders to evaluate the best options to meet the needs of our customers, while balancing affordability, reliability and sustainability.

# Cautionary Statement Regarding Forward-looking Information

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. These factors include but are not limited to:

- State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, including those related to climate change, as well as rulings that affect cost and investment recovery or have an impact on rate structures or market prices;
- The extent and timing of costs and liabilities to comply with federal and state laws, regulations and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments, are uncertain and difficult to estimate;
- The ability to recover eligible costs, including amounts associated with coal ash impoundment retirement obligations and costs related to significant weather events, and to earn an adequate return on investment through rate case proceedings and the regulatory process;
- The costs of decommissioning nuclear facilities could prove to be more extensive than amounts estimated and all costs may not be fully recoverable through the regulatory process;



Exhibit TF-3

- Costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- Industrial, commercial and residential growth or decline in service territories or customer bases resulting from sustained downturns of the economy and the economic health of our service territories or variations in customer usage patterns, including energy efficiency efforts and use of alternative energy sources, such as self-generation and distributed generation technologies;
- Federal and state regulations, laws and other efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could result in customers leaving the electric distribution system, excess generation resources as well as stranded costs;
- Advancements in technology;
- Additional competition in electric and natural gas markets and continued industry consolidation;
- The influence of weather and other natural phenomena on operations, including the economic, operational and other effects of severe storms, hurricanes, droughts, earthquakes and tornadoes, including extreme weather associated with climate change;
- The impact of the COVID-19 pandemic;
- The ability to successfully operate electric generating facilities and deliver electricity to customers including direct or indirect effects to the company resulting from an incident that affects the United States electric grid or generating resources;
- The ability to obtain the necessary permits and approvals and to complete necessary or desirable pipeline expansion or infrastructure projects in our natural gas business;
- Operational interruptions to our natural gas distribution and transmission activities;
- The availability of adequate interstate pipeline transportation capacity and natural gas supply;
- The impact on facilities and business from a terrorist attack, cybersecurity threats, data security breaches, operational accidents, information technology failures or other catastrophic events, such as fires, explosions, pandemic health events or other similar occurrences;
- The inherent risks associated with the operation of nuclear facilities, including environmental, health, safety, regulatory and financial risks, including the financial stability of third-party service providers;
- The timing and extent of changes in commodity prices and interest rates and the ability to recover such costs through the regulatory process, where appropriate, and their impact on liquidity positions and the value of underlying assets;
- The results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings, interest rate fluctuations, compliance with debt covenants and conditions and general market and economic conditions;
- Credit ratings of Duke Energy and its registered subsidiaries may be different from what is expected;
- Declines in the market prices of equity and fixed-income securities and resultant cash funding requirements for defined benefit pension plans, other post-retirement benefit plans and nuclear decommissioning trust funds;
- Construction and development risks associated with the completion of Duke Energy's capital investment projects, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner, or at all;
- Changes in rules for regional transmission organizations, including changes in rate designs and new and evolving capacity markets, and risks related to obligations created by the default of other participants;
- The ability to control operation and maintenance costs;

- The level of creditworthiness of counterparties to transactions;
- The ability to obtain adequate insurance at acceptable costs;
- Employee workforce factors, including the potential inability to attract and retain key personnel;
- The ability of subsidiaries to pay dividends or distributions to Duke Energy Corporation holding company (the Parent);
- The performance of projects undertaken by our nonregulated businesses and the success of efforts to invest in and develop new opportunities;
- The effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- The impact of United States tax legislation to our financial condition, results of operations or cash flows and our credit ratings;
- The impacts from potential impairments of goodwill or equity method investment carrying values; and
- The ability to implement our business strategy, including enhancing existing technology systems.

Additional risks and uncertainties are identified and discussed in Duke Energy's reports filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made and Duke Energy expressly disclaims an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.




Exhibit TF-3

BUILDING A SMARTER ENERGY FUTURE ®



**Exhibit TF-3**

**South Carolina Public Service Commission**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Exhibit TF-4**

**Duke Energy Carolinas and Duke Energy Progress Response to Vote Solar Data Request 2-10**

**DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

**Request**:

Please refer to the IRP Report at page 131, which states "The Company also released the Duke Energy 2020 Climate Report in April 2020, which offered insights into the complexities and opportunities ahead and provided an enterprise-level scenario analysis with an illustrative path to net-zero."

a) Has the Company conducted an assessment of climate risk on the assets, operations, and earnings of Duke Energy Carolinas and/or Duke Energy Progress specifically?
b) Provide any analyses conducted, commissioned, or consulted by the Company that seek to assess the incidence of climate risk on Duke Energy, Duke Energy Carolinas, and Duke Energy Progress's climate risk to assets, operations, and earnings?
c) Has the Company conducted an assessment of climate risk on ratepayers served by Duke Energy Carolinas and/or Duke Energy Progress specifically?
d) How has the Company integrated climate-related physical risks as described in the Duke Energy 2020 Climate Report into its Integrated Resource Plan? These include but are not limited to increased incidence of flooding, increased incidence of extreme precipitation, and increased incidence of heat waves.
e) Has the Company assessed the risk of stranded assets as contemplated on page 17 of the Duke Energy 2020 Climate Report?
f) Has the Company assessed the risk of increased property insurance premiums as contemplated in the Duke Energy 2020 Climate Report?
g) The 2020 Climate Report model assumes that gas "all natural gas combined-cycle units built in the 2020s are assumed to have a 20-year book life. Beyond 2030, all natural gas additions are assumed to be combustion turbines ("peakers") only." Does this IRP apply those same assumptions to future resource decisions? If not, why not?

**Response**:

a) DEC and DEP object to this request because the Duke Energy 2020 Climate Report was not used in any way in the development of the 2020 IRPs, and therefore the request seeks information that is not relevant and not likely to lead to the discovery of admissible evidence in this IRP proceeding.

b) DEC and DEP have not conducted any such analyses.

c) DEC and DEP have not conducted any such analyses.

d) DEC and DEP object to this request because the Duke Energy 2020 Climate Report was not used in any way in the development of the 2020 IRPs, and therefore the request seeks information that is not relevant and not likely to lead to the discovery of admissible evidence in this IRP proceeding.

e) DEC and DEP object to this request because the Duke Energy 2020 Climate Report was not used in any way in the development of the 2020 IRPs, and therefore the request seeks information that is not relevant and not likely to lead to the discovery of admissible evidence in this IRP proceeding. DEC and DEP further object to this request to the extent that it seeks information that is protected by the attorney/client privilege and/or attorney work-product doctrine.

f) DEC and DEP have not conducted any such analyses.

g) This IRP does not apply those same assumptions for the future resource. The Climate Report studied one pathway to achieving Net Zero. There are several options with decisions relating generating technology, resource cost recovery, impact to customers, and numerous others. The assumptions and restrictions on gas resources in the IRP reflect multiple other options for portfolios that do not include limited gas resources past 2030 or exploring alternative resource cost recovery strategies as presented in the Climate Report.

Person Responsible: Jennifer Canipe, P.E., Lead Engineer, Resource Planning & Analytics – Carolinas

**South Carolina Public Service Commission**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Exhibit TF-5**

**Con Edison 2019 Climate Change Vulnerability Study**

# Climate Change Vulnerability Study

December 2019

Exhibit TF-5

# Climate Change Vulnerability Study

December 2019

conEdison

In partnership with:

ICF

Lamont-Doherty Earth Observatory
COLUMBIA UNIVERSITY | EARTH INSTITUTE

With contributions from O'Neill Management Consulting, LLC, The Risk Research Group, Inc., and Jupiter Intelligence Inc.

Exhibit TF-5

# Table of Contents

# Executive Summary

In its 2013 rate case filing after Superstorm Sandy, Con Edison proposed $1 billion in storm hardening investments to build additional resiliency into its energy systems. Con Edison worked with a Storm Hardening and Resiliency Collaborative to recommend optimal investments for the proposed storm hardening funds, including the recommendation that Con Edison conduct a Climate Change Vulnerability Study (Study). As described by the New York State Public Service Commission, the purpose of this Study is to aid in the ongoing review of the Company's design standards and development of a risk mitigation plan.[1] Over the course of the Study, Con Edison regularly convened a stakeholder group to provide feedback, consisting of many of the same participants from the Storm Hardening and Resiliency Collaborative. The findings from the Study equip Con Edison with a better understanding of future climate change risks and strengthen the company's ability to more proactively address those risks.

This Study describes historical and projected climate changes across Con Edison's service territory, drawing on the best available science, including downscaled climate models, recent literature, and expert elicitation. Con Edison recognizes the global scientific consensus that climate change is occurring at an accelerating rate. The exact timing and magnitude of future climate change is uncertain. To account for climate uncertainty, the Study considered a range of potential climate futures reflecting both unabated and reduced greenhouse gas concentrations through time and evaluated extreme event "stress test" scenarios.

This Study evaluates present-day infrastructure, design specifications, and procedures against expected climate changes to better understand Con Edison's vulnerability to climate-driven risks. This analysis identified sea level rise, coastal storm surge, inland flooding from intense rainfall, hurricane-strength winds, and extreme heat as the most significant climate-driven risks to Con Edison's systems. Con Edison has unique energy systems, and vulnerabilities vary across those systems. The utility's electric, gas, and steam systems are all vulnerable to increased flooding and coastal storms; workers across all commodities are vulnerable to increasing temperatures; and the electric system is also vulnerable to heat events.

While Con Edison already uses a range of measures to build resilience to weather events, the vulnerabilities identified in this Study guide the company to pursue additional strategies to mitigate climate risks. The Study establishes an overarching framework that can work to strengthen Con Edison's resilience over time. While many adaptation strategies focus on avoiding impacts altogether, a comprehensive resilience plan also requires a system that can reduce and recover from impacts, particularly following outages.

Over the course of 2020, Con Edison will develop and file a Climate Change Implementation Plan, which will specify a governance structure and a strategy for implementing adaptation options over the next 5, 10, and 20 years. While this Study assesses vulnerabilities within Con Edison's present-day systems to a future climate, the implementation plan must also consider the evolving market for energy services, and potential changes to services and infrastructure driven by customers, government policy and external actions over time.

[1] Cases 13-E-0030, 13-G-0031, 13-S-0032, Order Adopting Storm Hardening and Resiliency Collaborative Phase Three Report Subject to Modifications (January 25, 2016).

## The Need for a Study

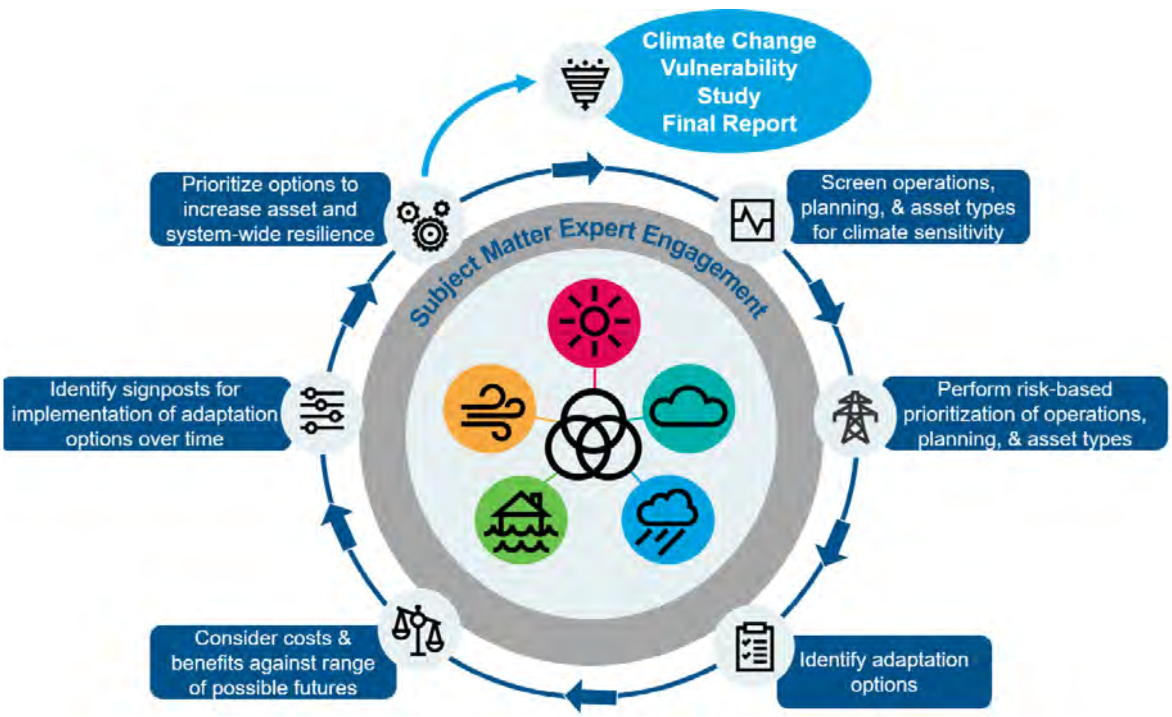
The New York State Public Service Commission approved an Order and funding for Con Edison to conduct a Climate Change Vulnerability Study, with a requirement for delivery by the end of 2019. The Con Edison Department of Strategic Planning undertook this Study with support from more than 100 subject matter experts throughout the company and in collaboration with ICF's climate adaptation and resilience experts and Columbia University's Lamont-Doherty Earth Observatory. The Study was designed to meet three primary goals:

Con Edison's resilience to climate change has important implications for increasingly interconnected societal, technological, and financial systems that the company serves.

1. Research and develop a shared understanding of new climate science and projected extreme weather for the service territory.
2. Assess the risks of potential impacts of climate change on operations, planning, and physical assets.
3. Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

The Study used an integrated approach to achieve these goals, as shown in Figure 1.

**Figure 1** ■ General approach overview: The process cycles through the steps for each climate hazard, beginning with 'Screen operations, planning, and asset types for climate sensitivity'. The process results in the Climate Change Vulnerability Study Final Report.



## A New Understanding of Climate Science and Extreme Weather

Con Edison will face new challenges from a rapidly changing climate through the 21st century. To better understand these challenges, the Study characterized historical and projected changes to climate hazards within the service territory to estimate the magnitude and timing of potential climate vulnerabilities. Climate variables that present outsized impacts to Con Edison include temperature, humidity, precipitation, sea level rise, and extreme events, such as rare hurricanes and long-duration heat waves.

### Temperature

Average and maximum air temperatures are projected to increase throughout the century relative to historical conditions. Assuming unabated greenhouse gas concentrations, Con Edison could experience up to 23 days per year in which maximum temperatures exceed 95°F by 2050 relative to 4 days historically. Heat waves with 3 or more days when *average* temperatures exceed 86°F in Central Park are projected to occur up to 5 and 14 times per year by 2050 and 2080, respectively, relative to 1 heat wave every 5 years historically.

### Humidity

The frequency of very high heat index thresholds, which combines both temperature and humidity, is projected to increase dramatically through the century. The number of days per year where the heat index equals or exceeds 103°F could increase by 7 to 26 days by 2050, compared with only 2 days historically. In addition, Con Edison evaluates the relationship of system load to an index called temperature variable (TV), which is similar to a heat index, but considers the persistence of heat and humidity over several days. Looking forward, TV thresholds that historically occur only once per year (e.g., 86°F) are projected to become common occurrences within a generation, occurring between 4 and 19 times per year by 2050 and between 5 and 52 times per year by 2080 based on reduced and unabated greenhouse gas concentrations, respectively.

### Precipitation

Con Edison's service territory experiences rainfall, downpours, snowfall, and ice. Climate change is projected to drive heavier precipitation across these event types. For example, the heaviest 5-day precipitation total could be 11.8 inches at Central Park by 2050, which represents a 17% increase over the historical reference period. Ultimately, projections point to a future defined by more frequent heavy precipitation, likely accompanied by smaller increases in the frequency of dry or light precipitation days.

### Sea Level Rise

Sea levels are very likely to rise between 0.62 and 1.94 feet by 2050. In turn, rising sea levels will have profound effects on coastal flooding, as sea level rise increases both the frequency and height of future floods. For example, the flood height associated with the 1% annual chance flood (i.e., the so-called 100-year flood) in New York City is projected to increase from 8.3 feet to as much as 13.3 feet by 2100 relative to mean sea level at the Battery tide gauge. By the end of the century, today's annual chance flood could occur at every high tide.

### Extreme Events

Extreme events are low-probability and high-impact phenomena, such as hurricanes and long-duration heat waves. While difficult to simulate in climate models, a growing body of evidence suggests that many extreme events will increase in frequency and intensity as a result of climate warming. This Study considers high impact "worst-case"[2] extreme event scenarios, including a prolonged heat wave, a Category 4 hurricane, and an unprecedented nor'easter, to understand these changes and their impacts on Con Edison.

## Characterization of Con Edison's Vulnerabilities to Climate Risks

### Heat and Temperature Variable

The core electric vulnerabilities to increasing temperature and TV include increased asset deterioration, decreased system capacity, increased load, and decreased system reliability. Since the internal temperature of electric power equipment is determined by the ambient temperature as well as the power being delivered, higher ambient temperatures increase the internal operating temperature of equipment.

Higher internal operating temperatures increase the rate of aging of the insulation of electric equipment such as transformers, resulting in decreased total life of the assets. Higher internal temperatures, resulting from higher average and maximum ambient temperatures, also reduce the delivery capacity of electric equipment such as transformers. In addition, higher ambient temperatures increase the operating temperature of overhead transmission lines, causing increased sagging. One remedy is to decrease the operational rating of the assets to reflect the new operating environment. However, derating the system due to increasing temperatures would effectively decrease the capacity of the system, and Con Edison will need to make investments to replace that capacity if it is needed.

Similarly, higher TV can cause higher peak loads due to increases in demand for cooling. Increases in load may also require investments in system capacity to meet the higher demand. The combination of decreased capacity and increased load is best addressed through Con Edison's existing 10- and 20-year load relief program. Addressing this combined risk is estimated to cost between $1.3 billion and $4.6 billion by 2050 (based on future projections using Representative Concentration Pathway (RCP) 4.5 10$^{th}$ and RCP 8.5 90$^{th}$ percentiles, respectively).

Increases in heat waves are expected to affect the electric network and non-network systems by decreasing reliability. Con Edison uses a Network Reliability Index (NRI) model to determine the reliability of the underground distribution networks. The Study's forward-looking NRI analysis found that with an increase in the frequency and duration of heat waves by mid-century, between 11 and 28 of the 65 underground networks may not be able to maintain Con Edison's standard of reliability by 2050, absent adaptation.

Outdoor worker safety may be a concern across all Con Edison commodities if heat index values rise as projected. When needed, Con Edison can implement safety protocols (e.g., shift modifications and hydration breaks) already practiced in mutual aid work that the company provided in hotter locations such as Florida and Puerto Rico. Similarly, to supply sufficient cooling in 2080, Con Edison's heating, ventilation, and air conditioning (HVAC) capacity will have to increase by 11% due to projected increases in dry bulb temperature. These systems have a roughly

[2] "Worst-case" scenarios are meant to explore Con Edison system vulnerabilities related to rare extreme weather events and formulate commensurate adaptation and resilience strategies. Scenarios represent one plausible permutation of extreme weather and the severity of actual events may exceed those considered.

15-year life span and therefore can be upgraded during routine replacements with minimal cost increases.

## Flooding from Precipitation, Sea Level Rise, and Coastal Storms

All underground assets are vulnerable to flooding damage (i.e., water pooling, intrusion, or inundation) from precipitation events, sea level rise, and coastal storms. Following Superstorm Sandy in 2012, Con Edison protected all infrastructure in the floodplain against future 100-year storms and 1 foot of sea level rise (e.g., submersible infrastructure, flood walls, pumps, elevation). Sea level rise projections suggest that Con Edison's 1 foot of sea level rise risk tolerance threshold may be exceeded as early as 2030 and as late as 2080.

Electric substations, overhead distribution, underground distribution, and the transmission system are sensitive to precipitation-based hazards, although the design of Con Edison's assets already mitigates some of these risks. For example, flooding from increased intense precipitation can damage non-submersible electrical equipment, although Con Edison designs all underground cables and splices to operate while submerged in water. In addition, all underground distribution equipment installed in flood zones and all new installations are submersible.

To assess future asset vulnerability to sea level rise and storm surge, the Study team analyzed the exposure of Con Edison's assets to 3 feet of sea level rise, while keeping the other elements of Con Edison's existing risk tolerance constant (i.e., a 100-year storm with 2 feet of freeboard). Of the 324 substations (encompassing generating stations, area substations, transmission stations, unit substations, and Public Utility Regulating Stations), 75 would be vulnerable to flooding during a 100-year storm if sea level rose 3 feet. In addition, 32 gas regulators and five steam generation stations would be exposed. Hardening all of these assets would cost approximately $680 million.

Both the gas and steam distribution systems are vulnerable to water entry, which can reduce system pressure and limit distribution capacity. In the gas system, low-pressure segments[3] are particularly vulnerable to this risk. In addition, the steam system is susceptible to "water hammer" events when a high volume of water collects around a manhole, causing steam in the pipes underneath to cool and condense. Interaction between steam and the built-up condensate may cause an explosion, both damaging the steam system and putting public safety at risk.

Across all commodities, increased winter precipitation can wash salt from city roads, causing an influx of salt-saturated runoff into manholes and percolation into the ground. Salt can cause equipment degradation, arcing, manhole fires or explosions, and failure of underground assets.

## Extreme and Multi-Hazard Events

The Study team reviewed the vulnerabilities of Con Edison's electric, gas and steam systems to future extreme events based on specific, worst case extreme event narratives (Category 4 hurricane, a strong nor'easter, and a prolonged heat wave) designed to stress-test these systems.

Storm surge driven by an extreme hurricane event (i.e., a Category 4 hurricane) has the potential to flood both aboveground and belowground assets. In addition, wind stress and windblown debris can lead to tower and/or line failure of the overhead transmission system and damage overhead distribution infrastructure, which could cause widespread customer outages.

[3] The Con Edison gas system contains piping operating at three pressures: low, medium, and high.

An extreme nor'easter may cause significant damage to assets across all commodities. During nor'easters, accumulation of radial ice can cause tower or line failure of the overhead transmission system. Similarly, snow, ice, and wind can damage the overhead distribution system.

Con Edison's systems are vulnerable to exceeding system capacity during extreme temperatures; gas systems may experience overloading during extreme cold, and electric systems during extreme heat.

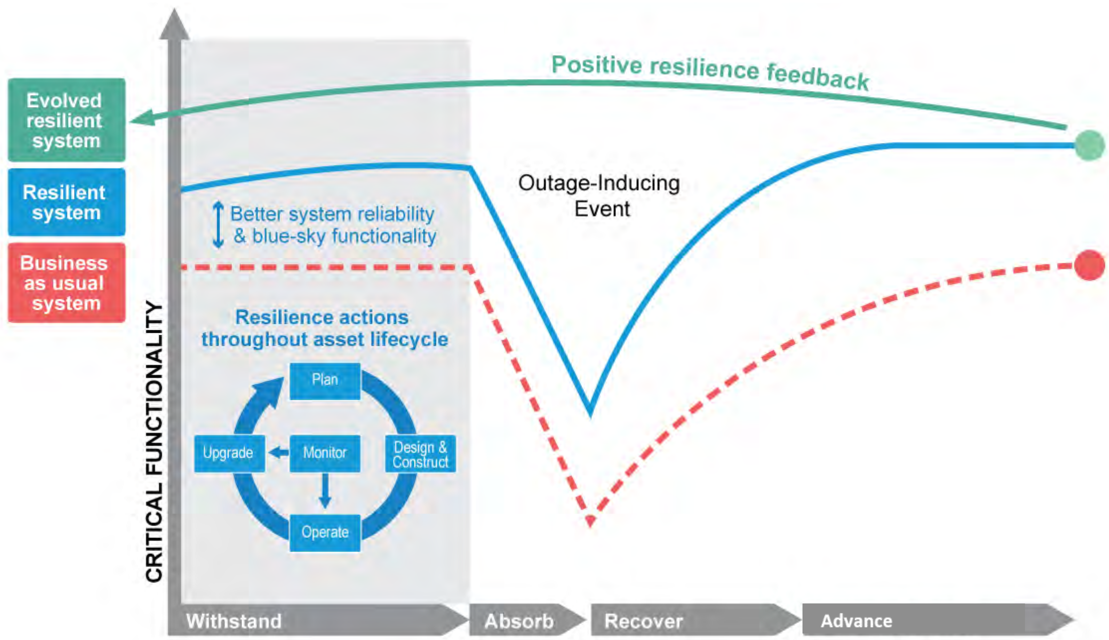
On an operational level, the increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts. Con Edison's current "full-scale" response, which calls for all Con Edison resources and extensive mutual assistance, is initiated when the number of customers out of service reaches approximately 100,000. However, low-probability extreme events can increase customer outages and outage durations by orders of magnitude, outpacing current levels of emergency planning and preparedness.

## Resilience Management Framework

A resilience management framework will help Con Edison build resilience over time.

To conceptualize how to systematically address vulnerabilities, the Study team developed a resilience management framework (Figure 2). The framework encompasses investments to better withstand changes in climate, absorb impacts from outage-inducing events, recover quickly, and advance to a better state. The "withstand" component of this framework prepares for both gradual and extreme climate risks through resilience actions throughout the life cycle of the assets. As such, many adaptation strategies fall under this category. Investments to increase the capacity to withstand also provide critical co-benefits such as enhanced blue-sky functionality and reliability of Con Edison's systems. The resilience management framework facilitates long-term adaptation and creates positive resilience feedback so that Con Edison's systems achieve better functionality through time. To succeed, each component of a resilient system requires proactive planning and investments.

**Figure 2** ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.




## Adaptation Measures to Address Vulnerabilities

> Con Edison already has undertaken a range of measures to build resilience; this Study identified additional adaptation options to address vulnerabilities under a changing climate.

Con Edison has already undertaken a range of measures to increase the resilience of its systems. For example, lessons learned and vulnerabilities exposed during past events, including Superstorm Sandy (2012) and the back-to-back nor'easters (winter storms Riley and Quinn, 2018), resulted in significant capital investments to harden the system. Looking forward, as Con Edison is investing in the system of the future—one with greater monitoring capabilities, flexibility, and reliability—it is simultaneously building a system that is more resilient to extreme weather events and climate change. In addition to new investments, Con Edison also conducts targeted annual updates to its system to ensure capacity and reliability, which help the company keep pace with recent changes in temperature and humidity.

## Withstand Gradual Changes in Climate and Extreme Events

Resilience actions should occur systematically throughout an asset's life cycle to enhance the ability to withstand changes in climate while also enhancing system reliability and blue-sky functionality. This can be accomplished through planning, designing, and upgrading assets in a resilient manner, with ongoing monitoring throughout.

### Plan

Incorporating climate change projections into Con Edison's routine planning processes will help identify capital needs and help the systems gradually adjust to changes in climate. Some of the types of planning processes and tools that may benefit from consideration of climate change include the following:

- Load and volume forecasting for all commodities
- Load relief planning for the electric system, which should include reduced system capacity and higher load due to warmer temperatures
- Working with utilities in other environments to understand how they plan and design their system for the climate Con Edison will experience in the future
- Long-range planning for all commodities
- Network reliability modeling and planning

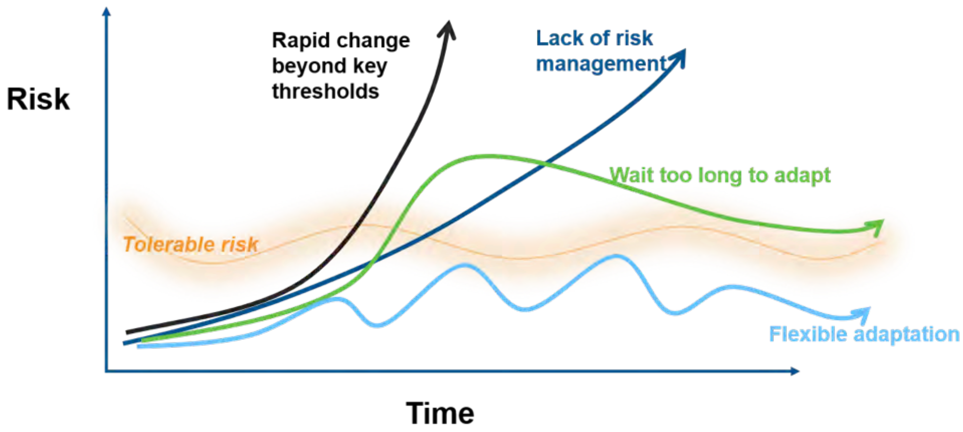
### Design

The key to designing resilient infrastructure is to update design standards, specifications, and ratings to account for likely changes in climate over the life cycle of the infrastructure. While there is uncertainty as to the exact changes in climate an asset will experience, selecting an initial climate projection design pathway allows engineers to design infrastructure in line with Con Edison's risk tolerance. The Study team suggests an initial climate projection design pathway that follows the 50th percentile merged RCP 4.5 and 8.5 projections for sea level rise and high-end 90th percentile merged RCP 4.5 and 8.5 projections for heat and precipitation.

### Upgrade

Changing design standards will influence the construction of new assets but does not address the vulnerability of existing assets. A flexible and adaptive approach to managing and upgrading assets will allow Con Edison to manage risks from climate change at acceptable levels, despite uncertainties about future conditions. The flexible adaptation pathways approach allows Con Edison to adjust adaptation strategies as more information about climate change and external conditions that may affect Con Edison's operations is learned over time. Figure 3 depicts how flexible adaptation pathways are based on flexible management to maintain tolerable levels of risk.

**Figure 3** ■ Flexible adaptation pathways in the context of tolerable risk and risk management challenges to non-flexible adaptation. Adapted from Rosenzweig & Solecki, 2014.




As conditions change over time, Con Edison will need to consistently track these changes to identify when decision making for additional or alternative adaptation strategies is required. This approach relies on monitoring indicators, or "signposts," that provide information which is critical for adaptive management decisions. Broad categories of signposts that Con Edison should consider monitoring include climate variable observations and best available climate projections; climate impacts; and policy, societal, and economic conditions. Predetermined thresholds for these conditions signal the need for a change in action, which support decisions on when, where, and how Con Edison can take action to continue to manage its climate risks at an acceptable level. The body of this report provides many specific examples of proactive investments in resilience and their signposts; a few selected examples are provided in Table 1.

**Table 1** ■ Examples of adaptation strategies to upgrade existing infrastructure and signposts to trigger action

| Strategy | Signpost |
|---|---|
| Implement electric reliability strategies, such as:<br>• Split the network into two smaller networks.<br>• Create primary feeder loops within and between networks.<br>• Install a distribution substation.<br>• Incorporate distributed energy resources and non-wires solutions.<br>• Design complex networks that consider combinations of adaptation measures. | Forward-looking network reliability index exceeds 1 per unit |
| Upgrade HVAC systems. | End of the existing asset's useful life |
| Retrofit ventilated equipment with submersible equipment to eliminate the risk of damage from water intrusion. | Expanded area of precipitation-based flooding; better maps of areas at risk of current and future precipitation-based flooding |
| Replace limiting wire sections with higher rated wire to reduce overhead transmission line sag during extreme heat wave events. Alternatively, remove obstacles or raise towers to reduce line sag issues. | Increased incidence of line sag; higher operating temperatures |
| Strategically expand program to elevate gas regulator vent line termini to include additional regulators exposed to floodplains associated with stronger storms and inland flooding. | When sea level rise exceeds 1 foot; reported or observed flooding in vicinity of asset without vent line protectors |

## Absorb and Recover from the Impacts of Extreme Events

It is neither efficient nor cost-effective for Con Edison to harden its systems to withstand every type of extreme event. Instead, Con Edison must use a broader suite of adaptation strategies to absorb and recover from the inevitable disruptions caused by extreme events exceeding their design standards. Con Edison currently incorporates "absorb" into its design and operations with, for example, a limited ability to control customer demand and shed load in extreme cases. A broader suite of strategies focuses on emergency preparedness, limiting customer impact and improving customer coping, including the following:

- Supporting the creation of resilience hubs (spaces that support residents and coordinate resources before, during, and after extreme weather events (Baja, 2018) and have continued access to energy services)
- Using smart meters to implement targeted load shedding to limit the impact to fewer customers during extreme events
- Strengthening staff skills for streamlined emergency response
- Planning for resilient and efficient supply chains
- Coordinating extreme event preparedness plans with external stakeholders
- Incorporating low-probability events into long-term plans
- Expanding extreme heat worker safety protocols
- Examining and reporting on the levels of workers necessary to prepare for and recover from extreme climate events
- Investing in energy storage, on-site generation, and energy efficiency programs

### Advance

Advancing to a better adapted, more resilient state after an outage-inducing event (i.e., building back better/stronger) begins with effective pre-planning for post-event reconstruction. Even with proactive resilience investments, events can reveal system or asset vulnerabilities. Where assets need to be replaced during recovery, having a plan already in place for selection and procurement of assets designed to be more resilient in the future can help to ensure that Con Edison is adapting to a continuously changing risk environment. Outage-inducing events also provide important opportunities to measure the performance of adaptation investments, helping to inform additional actions that further resilience.

## Next Steps

In 2020, Con Edison will develop an implementation plan that details priority actions needed in the next 5, 10, and 20 years.

As a next step from this Study, Con Edison will develop a detailed Climate Change Implementation Plan to integrate the recommendations from this Climate Change Vulnerability Study. The implementation plan will be developed in close coordination with Con Edison SMEs and will utilize quarterly meetings with external stakeholders. The implementation plan will consider updates in climate science, finalize an initial climate design pathway, integrate that pathway into company specifications and processes based on input from subject matter experts, develop a timeline for action with associated costs and signposts, and recommend a governance structure. Some key items for consideration in the implementation plan include determining the appropriate amount of proactive investment, changes in the policy/regulatory and operating environment and the establishment of a reporting structure.



# Introduction

## Study Background and Objectives

Con Edison's resilience to climate change has important implications for increasingly interconnected societal, technological, and financial systems that the company serves. Developing a shared understanding of Con Edison's vulnerability to climate change is critical to ensuring the continued strength of the company over the coming century. The Con Edison Climate Change Vulnerability Study (Study) has three primary goals:

1. Develop a shared understanding of new climate science and projected climate and extreme weather for the territory.
2. Assess the risks of potential climate change impacts on Con Edison's operations, planning, and physical assets.
3. Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

The Study was conducted as an outcome of the 2013 rate case. In 2013, Con Edison worked with a Storm Hardening and Resiliency Collaborative in parallel with the rate case to provide parties with an opportunity to fully examine proposals for plans to protect against storms. In 2014, the New York State Public Service Commission approved an Order and funding for Con Edison to implement measures to plan for and protect its systems from the effects of climate change, including conducting a climate change vulnerability study. The Study was developed by the Con Edison Department of Strategic Planning, in collaboration with ICF's climate adaptation and resilience experts and Columbia University's Lamont-Doherty Earth Observatory. The members of this partnership are collectively referred to as the Study team. The Study team relied on inputs and expertise from Con Edison subject matter experts (SMEs), including engaging more than 100 SMEs through a series of in-person meetings, teleconferences, and workshops.

## Guiding Principles

The Study used six key principles to efficiently meet its objectives and benefit Con Edison. The Study employed a decision-first and risk-based approach, applying the best available climate science to produce flexible and adaptive solutions and mitigate risks associated with climate change and extreme weather events. The Study process was transparent and interactive to ensure that it can be replicated and institutionalized.

**Decision-first approach.** The Study team used a decision-first approach, which focuses on understanding the broader vulnerabilities and constraints of the system, the objectives and needs of stakeholders, and the adaptation options available, before considering the projected changes in future climate. The Study team first identified the needs of decision makers (i.e., Con Edison leadership and SMEs) and worked from there to determine information requirements based on decision goals, instead of starting by amassing as much data as possible. This approach places a higher priority on understanding the decision-making context and providing enough information to inform those decisions, which helps to prioritize near- and long-term risks and develop effective solutions despite the existence of deep uncertainties related to future climate change.

**Risk-based approach.** The Study team employed a risk-based approach that considers both the likelihood and the consequence of potential changes in the climate. This involves identifying a comprehensive set of plausible future climate outcomes and assessing their probability and associated impact on Con Edison's service territory. Doing so allows Con Edison to assess its vulnerability to—and to prepare for—*high-probability and low-impact*, as well as *low-probability and high-impact*, outcomes.

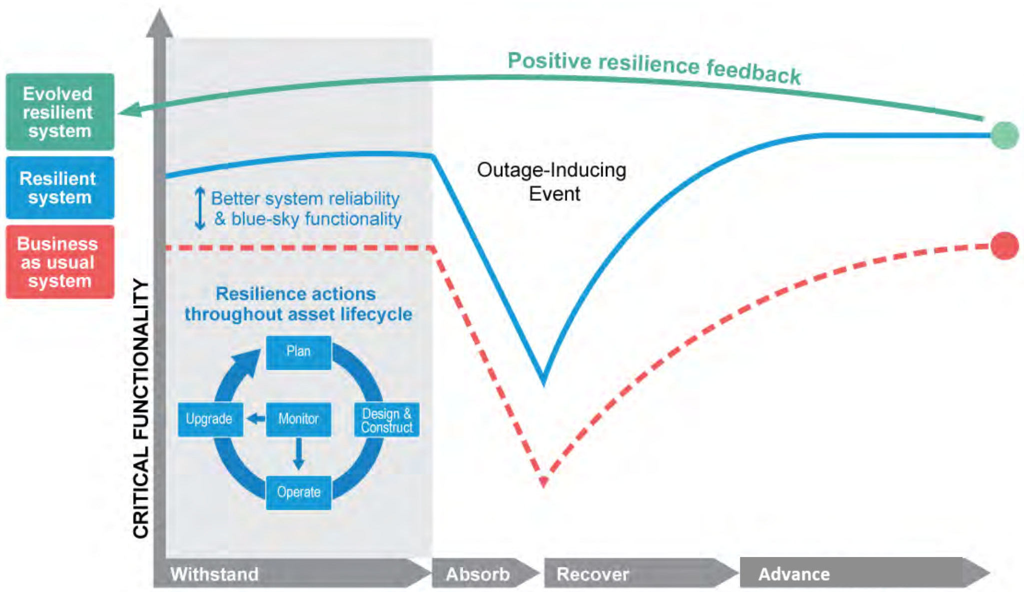
**Best available climate science.** The Study team prioritized continuous dialogues among climate scientists, climate adaptation specialists, and Con Edison SMEs to identify which climate scenarios, time periods, hazards, variables, and thresholds are important for Con Edison's operations, infrastructure, and planning. The Study team assessed multiple lines of evidence to capture historical climate conditions in the territory and employed a comprehensive set of Global Climate Models to identify the extent to which current climate conditions may change throughout the 21st century. Ultimately, the Study team synthesized climate information into metrics relating plausible effects of climatic changes on operations, infrastructure, and planning.

**Transparent and replicable.** A transparent and replicable approach allows Con Edison to institutionalize its adaptation strategy and increase its adaptive capacity over time. This will help SMEs establish their adaptation efforts into emerging policies and procedures, as well as train the next generation of SMEs in resilience building. Transparency also engenders trust with internal and external stakeholders.

**Flexible solutions and adaptive implementation.** A flexible and adaptive approach will allow Con Edison to manage risks from a changing climate at acceptable levels, despite uncertainties about future conditions. Adaptive implementation pathways, or flexible adaptation pathways, are a recognized approach to adaptation planning and project implementation that ensures adaptability over time in the face of uncertainty: changes in energy demand, technologies, population, and other driving factors, and refinements in the scientific understanding of future climate. Under the adaptive approach, resilience measures can be sequenced over time, allowing Con Edison to protect against near-term changes while leaving options open to protect against the wide range of plausible changes emerging later in the century.

**Resilience management framework.** The Study introduces a resilience management framework that allows Con Edison to mitigate risks associated with climate changes and extreme weather events most relevant to Con Edison's service territory (Figure 4). Resilient systems are composed of more than hardening measures alone, and instead consider measures that increase resilience throughout the life cycle of outage-inducing climate events. These measures include the system's capacity to "withstand," "absorb," and "recover" from climate risks and "advance" resilience. In this way, the resilient management framework is particularly important for addressing complex extreme events with significant uncertainties and extreme thresholds to build into hardening measures alone. In turn, resilient systems offer critical co-benefits, such as improved system reliability and blue-sky functionality, reduced consequences from non-climatic risks, and more resilient customers. A resilience management framework also facilitates long-term adaptation, which enhances the critical functionality of the system through time and creates positive resilience feedback. To succeed, each measure of a resilient system requires proactive planning and investments.

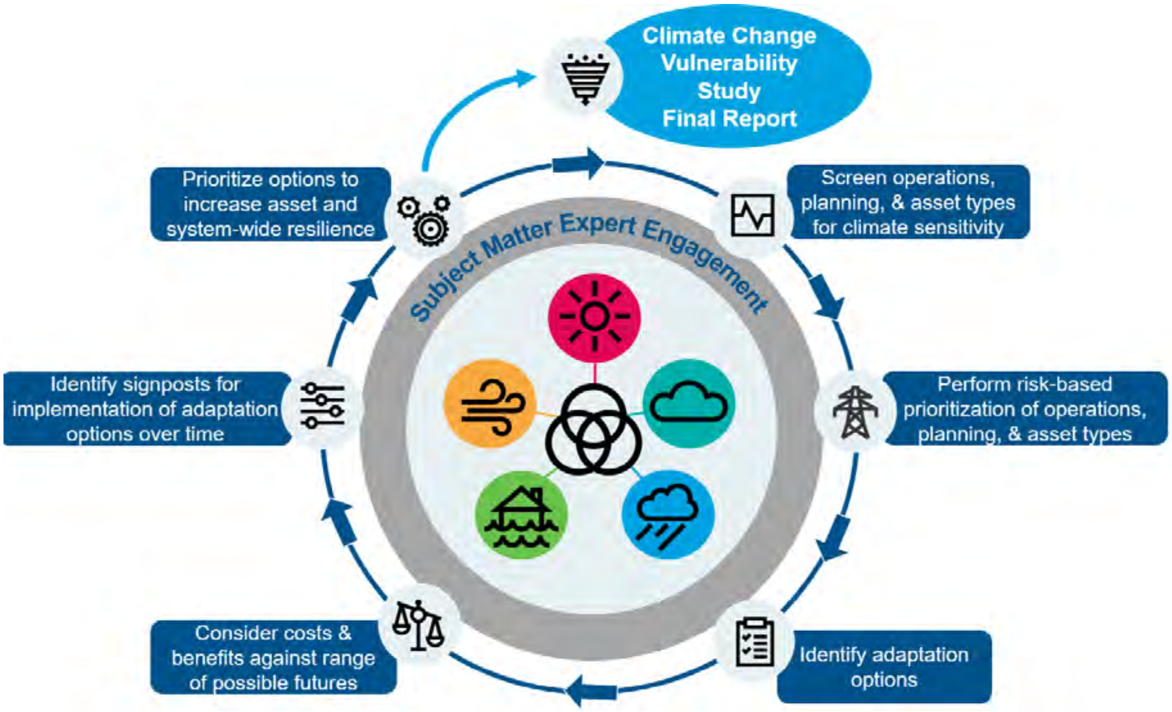
**Figure 4** ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.




## Study Methodology

The Study uses an integrated approach, with Con Edison SMEs providing support throughout the process. A rapid screen of the sensitivity of operations, planning, and assets (referred to for simplicity as "assets" throughout the rest of this document unless otherwise stated) for each climate change hazard provided the basis for a risk-based prioritization of assets. The Study team performed detailed analyses for the sensitive assets, including identifying a portfolio of adaptation options and qualitatively considering the financial costs, co-benefits, and resilience of each option. These detailed analyses will inform the development of flexible solutions and the further prioritization of assets and options to increase systemwide resilience during the creation of Con Edison's Climate Change Implementation Plan in 2020. Figure 5 depicts the Study's general approach.

**Figure 5** ■ General approach overview: The process cycles through steps for each climate hazard, beginning with 'Screen operations, planning, and asset types for climate sensitivity'. The process results in the Climate Change Vulnerability Study Final Report.




**Screen operations, planning, and asset types for climate sensitivity.** The Study began by establishing and confirming a clear set of climate change hazards and relevant thresholds for operations, planning, and asset types. The study team engaged SMEs to identify the extent to which each climate change hazard is a factor in asset design or operation and rate sensitivities by considering impacts from previous weather events and key climate information used in design or operation. Only assets with high sensitivity were considered in the subsequent risk-based prioritization process.

**Perform risk-based prioritization of operations, planning, and asset types.** Following the high-level screen for sensitivity, the Study team sought to prioritize operations, planning processes, and asset types for further analysis.

- Heat and humidity: Heat and humidity design standards vary across Con Edison assets, so the Study team used a risk workbook to guide SMEs through a structured process to identify the *probability of impact* (based on the probability of exceeding thresholds and the impact of threshold exceedance) and the *consequence of impact*. Together, these components create an *overall risk score* for each relevant asset and climate change hazard combination. *Consequence* is defined as the likely impact to the overall system given the possibility for damage or failure of the particular asset, and includes reliability, safety, environmental damage, and financial costs to the company or customers. The Study team identified several asset types and variable combinations with high sensitivity and high overall climate risk to carry forward as priorities in the analysis.
- Sea level rise and storm surge: Sea level rise and storm surge is a geographically defined hazard with a common design standard across all Con Edison assets. As such, there was a need to

identify potentially exposed assets rather than prioritize among them. The Study team used Geographic Information System (GIS) modeling to evaluate the specific type and number of assets that would be exposed under various future scenarios.

- Precipitation: Very few of Con Edison's assets have design standards tied to precipitation. For the few that were identified, the Study team evaluated whether the assets would withstand future increases in the intensity of precipitation events. In addition, the Study team worked with Con Edison SMEs to identify and prioritize the operational impacts of precipitation on the various commodities.
- Extreme events: By definition, the extreme events analyzed in the study exceed all existing Con Edison design standards. As such, the Study team conducted a workshop with SMEs to prioritize extreme event risks based on the following:
  - The potential for impacts on operations, planning, and assets
  - How prior major weather events affected assets and operations
  - The preparations that Con Edison has in place for future extreme events
  - How longer or more intense events might overwhelm current preparedness efforts

**Identify adaptation options.** For the identified vulnerabilities, the Study team developed adaptation response options through SME engagement, review of relevant literature, and lessons learned from adaptation options implemented in regions with similar challenges. Adaptation options include strategies to withstand a changing climate, such as engineering design, operations, and planning strategies, as well as strategies to absorb and recover from extreme events. The Study team considered adaptation options that are often already in use to manage the hazard, but which may require revision or updating to deal with changing risk. The Study team also considered both short-term and long-term solutions and took steps to understand and assess the limitations of adaptation options.

**Consider costs and benefits of adaptation options against a range of possible futures.** The Study team worked with SMEs to develop order of magnitude costs of the various adaptation strategies, where feasible. Where possible, the Study team conducted a multi-criteria analysis of the adaptation options to compare criteria that may be difficult to quantify or monetize, or that may not be effectively highlighted in the financial analysis.

**Identify signposts for implementation of adaptation options over time.** Evaluation of adaptation measures in the context of a continuously changing risk environment poses a challenge to typical project planning, design, and execution. It is important to ensure that decision-making processes support flexible solutions that allow for effective risk management in the face of irreducible uncertainties in projections of future climate conditions. The Study uses an adaptive implementation pathway approach to achieve this goal. The Study team designed a framework for "signposts," which represent information that will be tracked over time to help Con Edison understand how climate, policy, and process conditions change and, in turn, trigger additional action.

**Prioritize options to increase asset and systemwide resilience.** Once the prior steps were completed, the Study team circulated the findings to SMEs to allow them to strike, add, or refine strategies. This process resulted in the prioritized set of strategies included in this report.



# Historical and Future Climate

## Con Edison in a Changing Climate

Earth's climate is not static; it changes in response to both natural and human-caused drivers. The past decade was the warmest on record, and global atmospheric warming has increased at a faster rate since the 1970s (GCRP, 2017), which the global climate science community attributes to increasing human-caused greenhouse gas emissions (IPCC, 2013).

A growing body of research reveals that a range of climate hazards will likely increase in frequency and intensity as a result of atmospheric warming (GCRP, 2017; IPCC, 2013). For example, a warmer atmosphere increases the frequency, intensity, and duration of heat waves; holds more water vapor for heavy precipitation events; and accelerates ice loss from Earth's large ice sheets, contributing to sea level rise and coastal storm surge. These climate changes highlight how changes in the global climate system affect local climatology and weather in Con Edison's service territory. Local changes include both long-term mean changes, such as gradual increases in temperature and sea level, and changes in extreme events, such as heat waves, hurricanes, and storm surge. In most cases, long-term climate change amplifies and increases the likelihood of extreme events. In turn, climate changes and baseline climate hazards cause both direct (e.g., physical damage to infrastructure) and indirect (e.g., changing customer behavior) impacts across the electric, gas, and steam systems of Con Edison's business.

Rapid climate change will bring new challenges to Con Edison through the 21st century. This Study develops climate projections to characterize these challenges. Still, conceptualizing climate change in tangible terms is notoriously difficult. Another way to describe potential climate change is through climate analogs, which match expected future climate change at a location to current climate conditions in another. Under this perspective, New York City's temperature and precipitation by 2080 could more closely resemble current conditions in southern cities such as Memphis, TN, and Little Rock, AR, if greenhouse gas emissions continue unabated (Fitzpatrick & Dunn, 2019).[4]

[4] Climate analogs are illustrative and vary depending on the choice of evaluation metrics, decade, and climate scenario. In this case, analogs are determined using metrics for seasonal minimum and maximum temperature and total precipitation.

## Con Edison's Understanding and Assessment of Climate Change

The Study team developed improved, downscaled climate projections and used best available science to understand and evaluate climate change trends and potential extreme weather events across Con Edison's service territory over near- (2030), intermediate- (2050), and long-term (2080) time horizons.[5] This approach builds on methods used by the New York City Panel on Climate Change (NPCC) and introduces a range of benefits (see Table 2). The Study team focused on climate variables that could present outsized impacts to operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business. These include temperature, humidity, precipitation, sea level rise and coastal flooding, extreme events, and multiple—or compounding—events.

The primary tools for understanding future climate change are Global Climate Models (GCMs), which mathematically simulate important aspects of Earth's climate, such as changes in temperature and precipitation, natural modes of climate variability (e.g., El Niño and La Niña events), and the influence of human greenhouse gas emissions (GCRP, 2017). Over short timescales (i.e., years to decades), individual GCM projections can differ from one another due to unpredictable natural climate variability, differences in how models characterize small-scale climate processes, and their response to greenhouse gas emissions/concentration assumptions. For these reasons, future climate analyses often consider a large ensemble of GCMs to better discern long-term trends, account for uncertainty, and consider a fuller range of potential future climate outcomes. To this end, the Study team used a broad model ensemble (i.e., 32 GCMs) for each climate variable of interest to address the spread across models and provide a comprehensive view of future climate.

While GCMs use a finer spatial resolution than ever before, they still provide coarse-resolution estimates of future climate, with model grid cells typically extending approximately 100 kilometers on one side. To achieve a more accurate representation of local climate in the New York Metropolitan Region, the Study team bias-corrected and downscaled GCM projections (i.e., statistically adjusted simulations to bring them closer to observed data) using weather station data over a 1976–2005 historical reference period from three weather station locations spanning Con Edison's service territory, including Central Park, LaGuardia Airport, and White Plains Airport.[6]

GCM simulations are driven by a standard set of time-dependent greenhouse gas concentration trajectories called Representative Concentration Pathways (RCPs), developed by the Intergovernmental Panel on Climate Change (IPCC). RCPs consider different evolutions of fossil fuels, technologies, population growth, and other controlling factors on greenhouse gas emissions through the 21st century. To acknowledge uncertainty in future greenhouse gas concentrations, the Study team selected the commonly used RCPs 4.5 and 8.5 to drive each GCM, following precedent set by IPCC and NPCC. RCP 4.5 represents a moderately warmer future based on a peak in global greenhouse gas emissions around 2040. In contrast, RCP 8.5 represents a hotter future

[5] Columbia University's Lamont-Doherty Earth Observatory led the analysis of temperature, humidity, and precipitation projections and extreme event information. ICF provided insights into future climate conditions using localized constructed analog (LOCA) projections, analyzed sea level rise projections, and synthesized extreme event narratives. Jupiter Intelligence provided projections of extreme temperatures and the urban heat island effect.

[6] Technical information regarding bias-correction and downscaling methods used in this Study are provided in the appendices for the relevant climate variables.

corresponding to "business as usual" increases in greenhouse gas concentrations through the century.

The Study team used a model-based probabilistic framework to evaluate climate change hazards and account for model uncertainty under different RCP scenarios. Specifically, the Study team analyzed high-end estimates (e.g., the 90th percentile of projections across climate models), and mid-point (50th percentile) and low-end (10th percentile) projections for both RCPs. In doing so, the Study Team considered the range of potential climate outcomes across models and RCPs to form a comprehensive risk-based approach. Under this framework, the RCP 8.5 90th percentile approximates a stress test to characterize low probability, high-impact climate change, and its impact on Con Edison.

This Study builds on the approach used by NPCC. Table 2 provides a high-level overview of climate information advances developed as part of this Study.

**Table 2** ■ Overview of climate projection methods in this Study relative to the NPCC2 (2015) climate projections of record for New York City

| NPCC2 (Reference Projections) | Con Edison Study |
|---|---|
| Combined projections from two scenarios (RCPs 4.5 and 8.5) | Separate scenario projections |
| Four time periods (2020–2080) | Seven time periods (2020–2080) to align with planning processes |
| Single reference point (Central Park) | Multiple reference points tailored to the service territory (Central Park, White Plains, and LaGuardia) |
| Downscaling using the "delta method" | Downscaling using "quantile mapping" |
| Limited set of climate variables | Numerous Con Edison-specific variables and multi-variable projections (e.g., heat plus humidity) |

The Study also evaluates Con Edison's vulnerability to rare and complex extreme events, such as major hurricanes and long-duration heat waves, that may increase in intensity and frequency as a result of climate change. Such events play an outsized role in shaping the public's perception of climate change vulnerability and how institutions should address its unique challenges. While the Study team uses model-based probabilistic projections to inform many climate variables, such as long-term mean temperatures and sea level, it is more challenging to project the rarest events, such as a 1-in-100-year heat wave, and multi-faceted and difficult to model events such as hurricanes. Obstacles to modeling rare and complex extreme events include the brevity of the historical record relative to the rarity of the event, and challenges associated with modeling extremes that have important features at very small space and time scales.

To address these challenges, the Study team constructed a series of extreme event narratives based on historical analogs and the best available climate science. In contrast with model-based probabilistic projections, narratives represent plausible future worst-case scenarios[7] meant to stress-test Con Edison's system. The narratives merge a decision-first and risk-based approach, blending best available science with decision maker-defined high impacts to develop a better understanding of Con Edison's vulnerability to rare, complex extreme events.

The timing and magnitude of climate change over the coming century remains uncertain, particularly with respect to rare and multi-faceted extreme events. This uncertainty presents challenges for institutions such as Con Edison in understanding the potential effects of climate change and the associated risks to their business, operations, and financial performance.

Scenario analysis is a proven way to address these challenges. For example, Task Force on Climate-Related Financial Disclosures (TCFD) scenarios use forward-looking projections to provide a framework to help companies prepare for risks and opportunities brought about by climate change. The scenarios used in this Study are similarly hypothetical constructs, but differ from TCFD scenarios in that they provide quantitative details regarding future extreme event conditions (e.g., regarding specific storm characteristics) so that Con Edison can better plan for specific impacts to assets and infrastructure. Ultimately, this Study uses both climate science and stakeholder-driven perspectives to develop plausible, high impact worst-case scenarios designed to stress-test Con Edison's system.

## Overview of Climate Science Findings Relevant to Con Edison

The Study team's analysis characterized historical and future changes in temperature, humidity, precipitation, sea level rise, and extreme events within Con Edison's service territory. This information supports a risk-based understanding of potential climate-related vulnerabilities within the company's operations, planning, and physical assets. The sections below provide an overview of projected climate changes relevant to Con Edison. While projections were prepared for Central Park, LaGuardia, and White Plains as described above, this section commonly uses Central Park as a reference point due to its central location and because it currently serves as a reference point for many Con Edison operations. The report appendices contain detailed information on other locations and the full scope of climate projections and corresponding vulnerabilities developed for this Study.

### Temperature

Both average and maximum air temperatures are projected to increase throughout the century relative to historical conditions (Figure 6). Climate model projections reveal significant increases in the number of days per year in which average temperatures exceed 86°F (up to 26 days per year, relative to a baseline of 2 days) and maximum temperatures exceed 95°F (up to 23 days per year from a baseline of 4 days; Figure 7) by 2050. At the same time, winter minimum temperatures are expected to fall below 50°F as many as 40 fewer times per year than in the past by mid-century, representing a 20% decrease.

[7] Worst-case scenarios are meant to explore Con Edison system vulnerabilities related to rare extreme weather events and formulate commensurate adaptation and resilience strategies. Scenarios represent one plausible permutation of extreme weather and the severity of actual events may exceed those considered.

**Figure 6** ■ Historic (black line) and projected (colored bands) average air temperature in Central Park during the summer under two greenhouse gas concentration scenarios (RCPs 4.5 and 8.5)

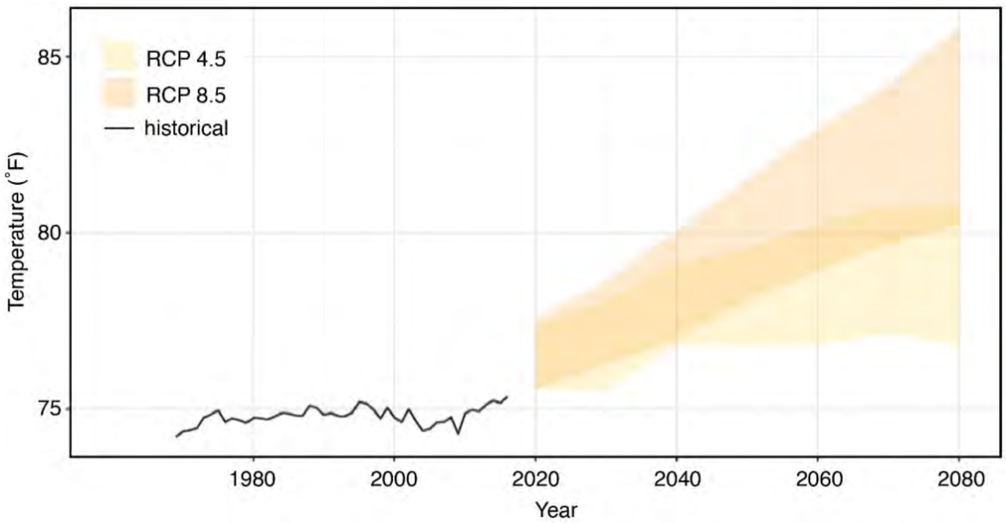
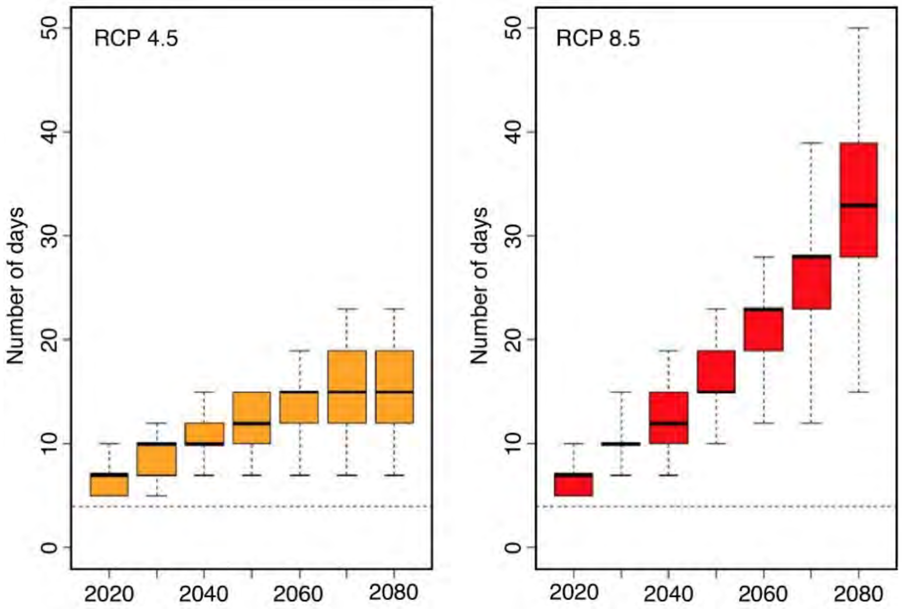



**Figure 7** ■ The average number of days per year with maximum summer air temperatures exceeding 95°F in Central Park under two greenhouse gas concentration scenarios (RCPs 4.5 and 8.5). The dashed horizontal lines show the historical average number of days. Box plots correspond to the 10th, 25th, 50th, 75th, and 90th percentile projections.

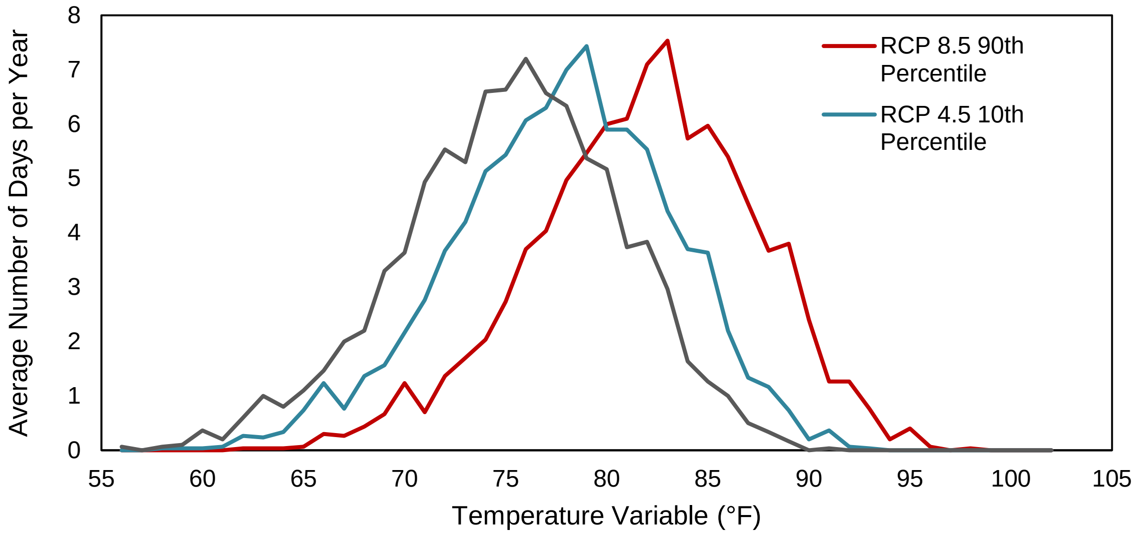



Multi-day heat events, known as heat waves, create potential risks for Con Edison as they drive demand for air conditioning and stress electrical and infrastructure systems. The number of heat waves, defined here as 3 or more consecutive days when *average* temperatures exceed 86°F in Central Park, is projected to increase up to 5 and 14 events per year by 2050 and 2080, respectively, relative to 0.2 events per year historically. The magnitudes of temperature increases are projected to be greatest at LaGuardia and Central Park and smaller at White Plains.

## Humidity

The New York Metropolitan Region is susceptible to significant combinations of heat and humidity, which cannot be captured by temperature alone. The combination of temperature and humidity drives electric demand within Con Edison's service territory. To address this, the company currently evaluates the potential for high loads using an index referred to by Con Edison as temperature variable (TV),[8] which incorporates considerations of both temperature and humidity. Looking forward, TV thresholds that have historically occurred only once per year (e.g., 86°F), are projected to become common occurrences within a generation, occurring between 4 and 19 times per year by 2050 and 5 and 52 times per year by 2080, under the RCP 4.5 10th percentile and RCP 8.5 90th percentile, respectively, at LaGuardia (Figure 8). Smaller increases are expected at White Plains.

**Figure 8** ■ Distributions showing historical (black line) and 2050 projected (blue and red lines) summer (June–August) daily electric TV at LaGuardia Airport. The 2050 projections show both the RCP 8.5 90th percentile and the RCP 4.5 10th percentile distributions.



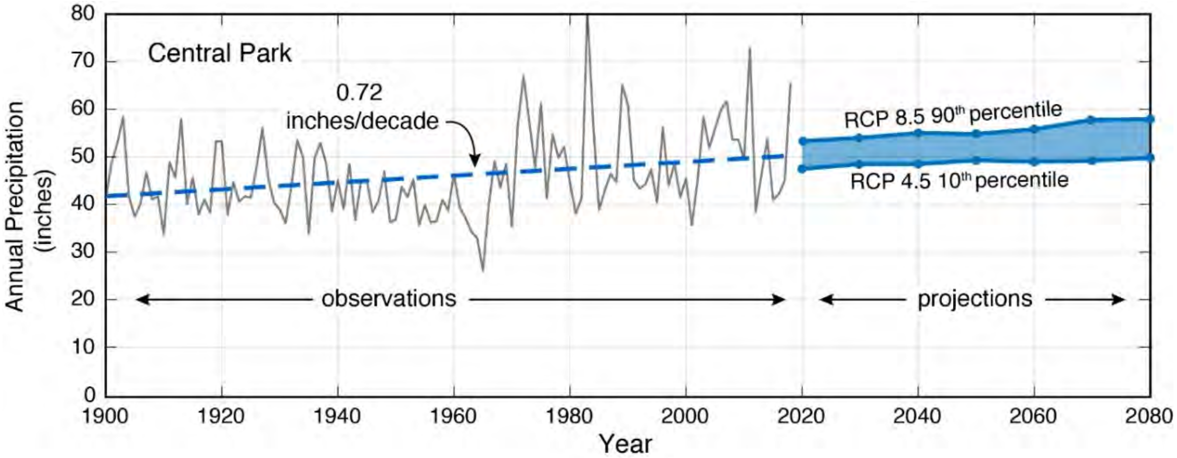

The heat index is a typical indicator of "how hot it feels," which considers the combined effect of air temperature and relative humidity. The index assesses health risks associated with overheating, including for Con Edison employees working under hot conditions. Looking forward, the frequency of occurrence for very high heat index thresholds is projected to increase dramatically through the century. Projections reveal that the number of days per year when the heat index equals or exceeds 103°F at LaGuardia could increase to between 7 and 26 days by 2050 under the RCP 4.5 10th percentile and the RCP 8.5 90th percentile, respectively, compared to only 2 days historically.

[8] Temperature variable is calculated using the weighted time integration of the highest daily recorded 3-hour temperature and humidity over a 3-day period. The reference TV for Con Edison is 86°F, which approximates a heat index of 105°F.

## Precipitation

Con Edison's service territory experiences a range of precipitation events over a range of timescales, including rainfall, downpours, snowfall, and ice. Climate change is projected to drive heavier precipitation across these event types because a warmer atmosphere holds more water vapor and provides more energy for strong storms. Looking forward, average annual precipitation is projected to increase by 0% to 15% relative to the historical baseline in Central Park through 2050 (Figure 9).

**Figure 9** ■ Observed and projected annual precipitation at Central Park. Projections show potential annual precipitation under both the RCP 8.5 90th percentile and the RCP 4.5 10th percentile. Projections represent 30-year time averages (shown as blue circles), which reveal the long-term trend, but underrepresent year-to-year variability. The dashed line represents the linear trend though the observational record, with observed increases given in inches per decade.




Projections of heavy rainfall reveal similar increases. For example, the heaviest 5-day precipitation amount could be 11.8 inches at Central Park by 2050, which represents a 17% increase over the historical reference period. Data from the Northeast Regional Climate Center[9] show that 25-year, 24-hour precipitation amounts at Central Park, LaGuardia, and White Plains could increase by 7% to 14% and 10% to 21% by mid- and late-century, respectively. Ultimately, projections point to a future defined by more frequent heavy precipitation and downpours, likely accompanied by smaller increases in the frequency of dry or light precipitation days (GCRP, 2017).

Projections for changes in snow and ice are more uncertain than those for rainfall. Overall, models project a decrease in snowstorm frequency corresponding to a warming climate (Zarzycki, 2018). However, while the likelihood of a given storm producing snow instead of rain will decrease in the future, if atmospheric conditions are cold enough to support frozen precipitation, then storms are expected to produce more snow (or ice) than during the present day (Zarzycki, 2018).

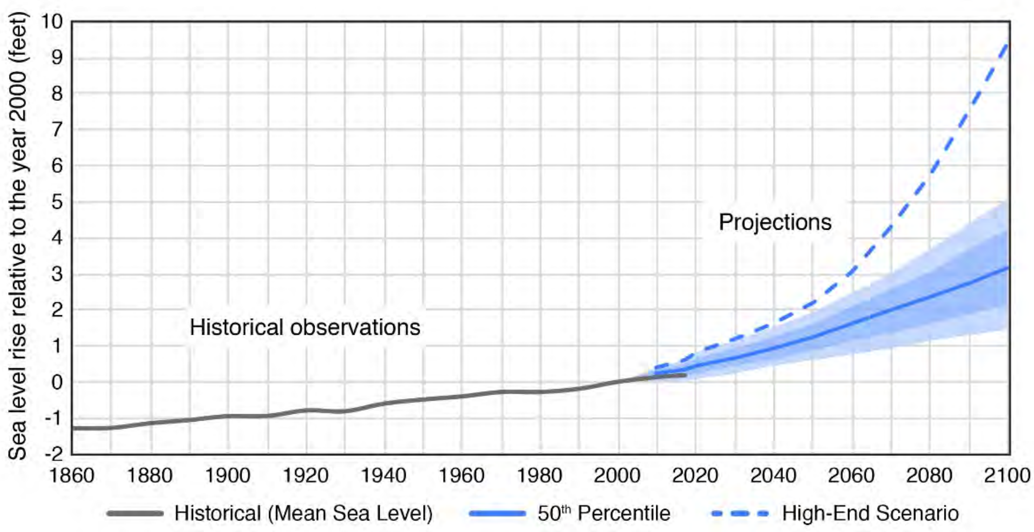
## Sea Level Rise

A range of underlying factors, including thermal expansion of the ocean, the rate of ice loss from glaciers and ice sheets, atmosphere and ocean dynamics, and vertical coastline adjustments determine local sea level rise within Con Edison's service territory. State-of-the-art probabilistic

[9] http://ny-idf-projections.nrcc.cornell.edu/

projections (Kopp et al., 2014; 2017) determined these contributions and characterized the rate of future sea level rise in the region under both RCPs 4.5 and 8.5 (e.g., Figure 10). These sea level rise projections include a unique high-end scenario driven by rapid West Antarctic ice sheet mass loss in the later 21st century (DeConto & Pollard, 2016; Kopp et al., 2017). Con Edison has always implemented anti-flooding measures. Following Superstorm Sandy in 2012, the company implemented a minimum protection design standard of "FEMA plus three feet,"[10] allowing for 1 foot of sea level rise. In turn, forward-looking projections determine when sea level rise may exceed Con Edison's established risk tolerance of 1 foot of sea level rise.

**Figure 10** ■ Historical and projected sea level rise in New York City under RCP 8.5 relative to the year 2000. The grey line shows historical mean sea level at the Battery tide gage. Projections are relative to the 2000 baseline year. The solid blue line shows the 50th percentile of projected sea level rise. The darker shaded area shows the likely range (17th–83rd percentiles), while the lighter shaded area shows the very likely range (5th–95th percentiles). The blue dashed line depicts a high-end projection scenario driven by rapid West Antarctic ice sheet mass loss in the later 21st century (DeConto & Pollard, 2016; Kopp et al., 2017).




Sea level rise will very likely be between 0.62 and 1.74 feet and 0.62 and 1.94 feet at the Battery tide gauge in lower Manhattan by 2050 under RCPs 4.5 and 8.5, respectively. Projections suggest that Con Edison's 1-foot sea level rise risk tolerance threshold may be exceeded as early as 2030 and as late as 2080.

In turn, rising sea levels will have profound effects on coastal flooding, as sea level rise is expected to increase both the frequency and height of future floods (Figure 11). For example, the flood height associated with the 1% annual chance (100-year) flood in New York City is projected to increase from 10.9 feet to as much as 15.9 feet under RCP 8.5 by 2100, representing an increase of close to 50%.[11] Similarly, today's 0.2% annual chance (500-year) flood could look like a 10% annual

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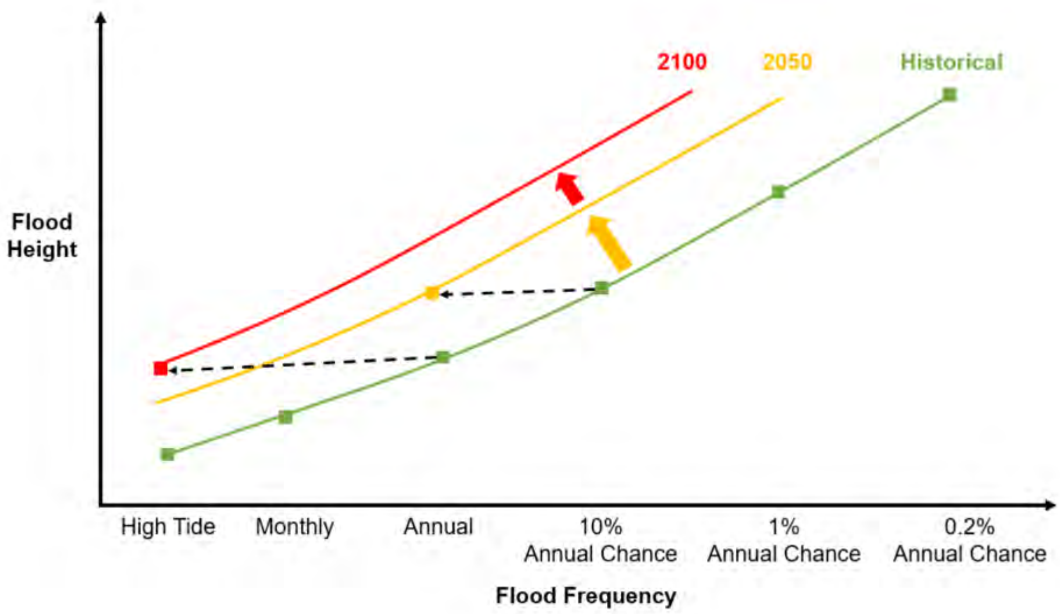
[10] This includes the FEMA 1% annual flood hazard elevation, 1 foot of sea level rise and 2 feet of freeboard (to align with 2019 Climate Resiliency Design Guidelines published by the New York City Mayor's Office of Recovery and Resiliency).
[11] Flood values are above the mean lower low water (MLLW) datum at the Battery tide gauge. MLLW is measured as 2.57 feet below mean sea level at the Battery.

chance (10-year) flood in 2100, making it 50 times more likely. At the end of the century, today's annual chance flood could occur at every high tide.

**Figure 11** ■ Projected changes in the frequencies of historical flood heights as a result of sea level rise. Dashed lines represent projected changes in frequency; solid lines represent illustrative changes in flood frequency coinciding with flood heights




## Extreme Events

Rare extreme events, such as strong hurricanes and long-duration heat waves, are low-probability and high-impact phenomena that pose outsized risks to infrastructure and services across Con Edison's service territory. While modeling rare extreme events remains challenging and at the forefront of scientific research, a growing body of evidence suggests that many types of extreme events will likely increase in frequency and intensity as a result of long-term climate warming.

To address these challenges, the Study team used feedback from Con Edison SMEs to prioritize a suite of extreme event narratives that combine plausible worst-case events from both climatological and impact perspectives. In turn, the narratives represent future worst-case scenarios designed to stress-test Con Edison and the local and regional systems with which it connects. The chosen narratives considered a prolonged heat wave, a Category 4 hurricane, and an unprecedented nor'easter striking the region.

Best available climate science reveals that climate change will likely amplify these extremes over the coming century. For example, the mean heat wave duration in New York City is expected to increase to 13 and 27 days by 2050 and 2080, respectively, based on RCP 8.5 90th percentile projections (NPCC, 2019). At the same time, broadscale atmospheric and ocean surface temperature changes may drive stronger hurricanes and extratropical cyclones. Looking forward, while the total number of hurricanes occurring in the North Atlantic may not change significantly over the next century, the percentage of very strong and destructive (i.e., Categories 4 and 5) hurricanes is projected to increase in the North Atlantic basin (IPCC, 2013). It can therefore be argued that climate change could make it more likely for one of these storms to impact the New York Metropolitan Region, although the most dominant factor will remain unpredictable climate and weather variability (Horton & Liu, 2014). Finally, some recent studies project a 20% to 40% increase in nor'easter strengthening (i.e., producing the types of storms with destructive winds) immediately inland of the Atlantic coast by late-century, suggesting stronger storms may more frequently impact the New York Metropolitan Region with heavy precipitation, wind, and storm surge (Colle et al., 2013)

## Signposts: Monitoring and Climate Science Updates

Understanding Con Edison's vulnerabilities to climate change and adapting to those changes over time require a robust monitoring strategy. Climate change evolves through time, meaning that the current spread of potential future climate outcomes produced by models will eventually converge on a smaller set of climate realizations. To keep up with this evolution, a range of signposts are required to sufficiently gauge relevant rates of change and best prepare Con Edison for the most likely climate future.

An awareness of past and present climate conditions in Con Edison's service territory is critical for understanding the trajectory of climate change. Con Edison currently operates a number of stations that monitor climate variables and is finalizing plans to expand the number of monitoring locations. Increasing observations from monitoring stations will help measure both local climate variations and climate change through time, informing Con Edison's climate resilience planning. Citywide observations of variables, such as hourly temperatures, precipitation, humidity, wind speed, and sea level, are paramount to building a broad and usable set of guiding measurements. With accurate and up-to-date data on these variables, Con Edison can better monitor both changing conditions and potential points of vulnerability.

Con Edison can supplement monitoring through a regularly updated understanding of the best available projections as models and expert knowledge evolve over time. Climate projections continually improve as the scientific community better understands the physical, chemical, and biological processes governing Earth's climate and incorporates them into predictive models. Ultimately, Con Edison wants to draw on the best available data and projections that are driven by scientific consensus, but also are accessible and applicable to company needs. Signposts for updating climate science used to inform potential Con Edison vulnerabilities include major science advancements, such as the release of the new Coupled Model Intercomparison Project (CMIP) projections and their integration and validation in new IPCC, NPCC, and National Climate Assessment (NCA) reports. These assessments include updated probabilistic climate projections representing model advancements, the best available science regarding difficult-to-model extreme events, and literature reviews reflecting the current state of science as guided by leading experts. Such signposts could justify Con Edison updating their climate projections of record to reflect the best available science or projections that represent a significant departure from previous understanding. Historically, major scientific reports, such as the IPCC, have been released about every 6 to 7 years, which provide a potential constraint on how frequently Con Edison's understanding of climate change within the service territory might be revisited.



# Existing Efforts and Practices to Manage Risks Under a Changing Climate

Although this Study is Con Edison's first comprehensive assessment of climate change vulnerabilities, Con Edison has already undertaken a range of measures to increase the resiliency of its system. Lessons learned and vulnerabilities exposed during past events, most recently Superstorm Sandy (2012) and the back-to-back nor'easters (winter storms Riley and Quinn, 2018), resulted in significant capital investments to harden the system.

In addition, as Con Edison invests in the system of the future—one with greater monitoring capabilities, flexibility, and reliability—it is simultaneously building a system that is more resilient to extreme weather events and climate change. For example, grid modernization will both increase efficiency and enhance monitoring capabilities by employing new technology and modes of data acquisition. Con Edison is planning to support numerous grid modernization initiatives that target energy storage technologies, communications systems, distributed energy resources infrastructure and management, complex data processing, and advanced grid-edge sensors (Con Edison, 2019). Con Edison additionally plans to modernize its Control Center to assume more proactive and centralized management of its complex distribution grid. Throughout these modernization initiatives, the company remains in close collaboration with the City of New York.

Con Edison also conducts targeted annual updates to its system to ensure capacity and reliability. These annual updates help the company keep pace in real time with changes in some key hazards. For example, when conducting electric load relief planning, Con Edison incorporates load forecasts that use an annually updated set of TV data. Although these forecasts are not grounded in future projections that consider climate change, they do account for the most recent climate trends and, as such, allow the company to stay in stride with the most current data.

Con Edison's previous adaptation measures have made targeted improvements in (1) physical infrastructure, (2) data collection and monitoring, and (3) emergency preparedness. The following measures are illustrative of these targeted improvements, but are not meant to be exhaustive of the efforts that Con Edison has undertaken:

## Physical Infrastructure

- Adopting the Dutch approach of "defense in depth" after Superstorm Sandy to protect all critical and vulnerable system components from coastal flooding risks, including the following:

  - Upgrading and increasing the number of flood barriers and other protective structures
  - Reinforcing tunnels
  - Replacing equipment with submersible equivalents in flood zones (e.g., targeted main replacement program, gas system)
  - Installing pumps and elevating infrastructure behind flood walls
- Protecting or elevating critical electrical infrastructure to the Federal Emergency Management Agency (FEMA) 100-year flood elevation plus 3 feet to account for sea level rise and freeboard during coastal storms
- Undertaking a targeted main replacement program that addresses low-pressure gas mains in low-lying areas, as well as other potentially vulnerable gas mains
- Installing isolation devices to limit the impact of damaged infrastructure on customers by de-energizing more granular sections of the system, when necessary
- Engaging innovative technologies to reduce the impact of extreme weather on electric distribution systems and quicken the recovery, including the following:
  - Demand response technologies that more efficiently regulate load
  - Automated splicing systems that reduce feeder processing times

## Data Collection and Monitoring

- Developing programs that employ machine learning and remote monitoring to identify areas of heightened vulnerability in Con Edison's systems, including the following:
  - Leak-prone areas of the gas distribution system
  - Gas system drip pots that require draining
- Initiating a more diligent inspection system that effectively assesses the functionality of assets, as well as their exposure to potential hazards (e.g., nearby vegetation), including the following:
  - Underground network transformers and protectors
  - Underground structures
  - Flushing of flood zone vaults
  - Rapid assessments of overhead feeders
  - Overhead system pole-by-pole inspection for specification compliance
- Future deployment of advanced metering infrastructure (AMI) throughout the service territory has the potential to both improve information flow to customers and help absorb the impacts of extreme events. Specifically, AMI might be able to rapidly shed load on a targeted network to help ensure demand does not exceed supply, which reduces potential damages and likelihood of network-wide outages in the event of an extreme event.

### Emergency Preparedness

- Improving contractor and material bases for post-storm repair crews and equipment, including the following:
  - Expanding and diversifying spare material inventories
  - Ensuring that all spare materials are housed in safe locations
- Conducting post-event debriefings to understand the impact of weather conditions on system performance
- Engaging with major telecommunications providers and enhancing communications systems among customer networks
- Facilitating equipment-sharing programs across New York State to ensure access to supplies during emergency response

Con Edison recognizes that the drivers behind future planning operations are inherently uncertain and is committed to both closely monitoring key signposts and continuously updating company investment plans and priorities.

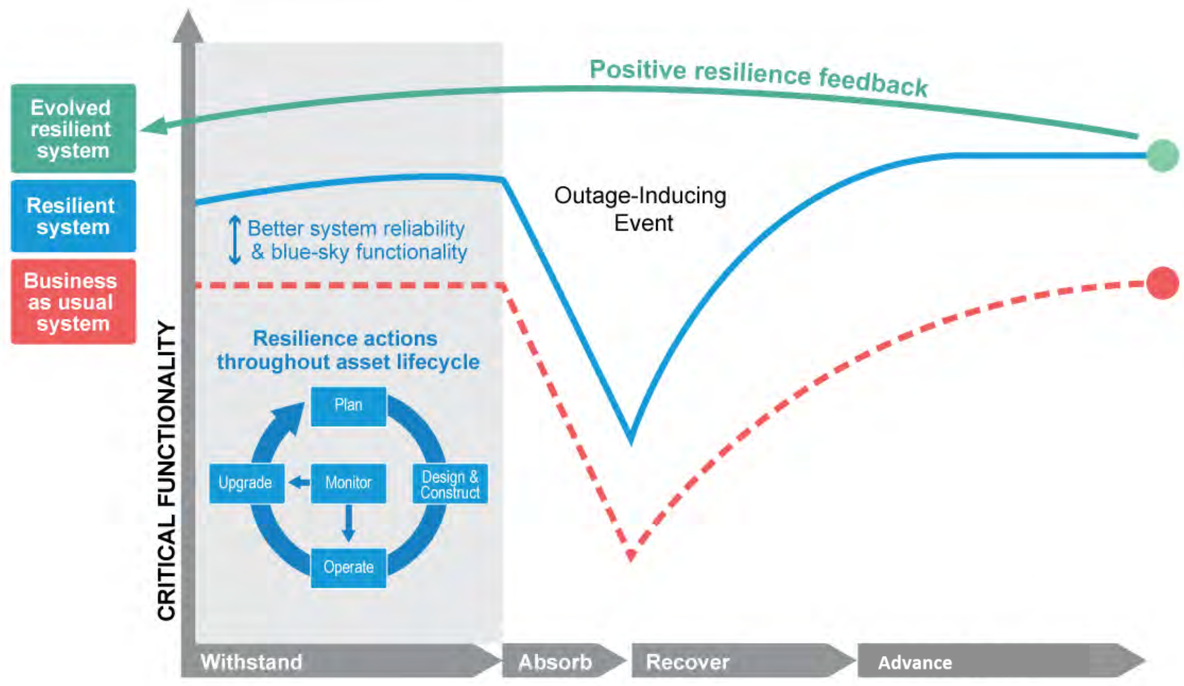
# Vulnerabilities, a Resilience Management Framework, and Adaptation Options

Con Edison may face greater vulnerabilities due to future changes in temperature, humidity, precipitation, sea level rise, and extreme weather events. To understand this, the Study team evaluated key vulnerabilities of Con Edison's present-day electric, gas, and steam systems under a changing climate. The physical assets, operations, and planning of each system are uniquely vulnerable. In turn, building a detailed understanding of key vulnerabilities is an important step toward identifying priority adaptation measures.

## Resilience Management Framework

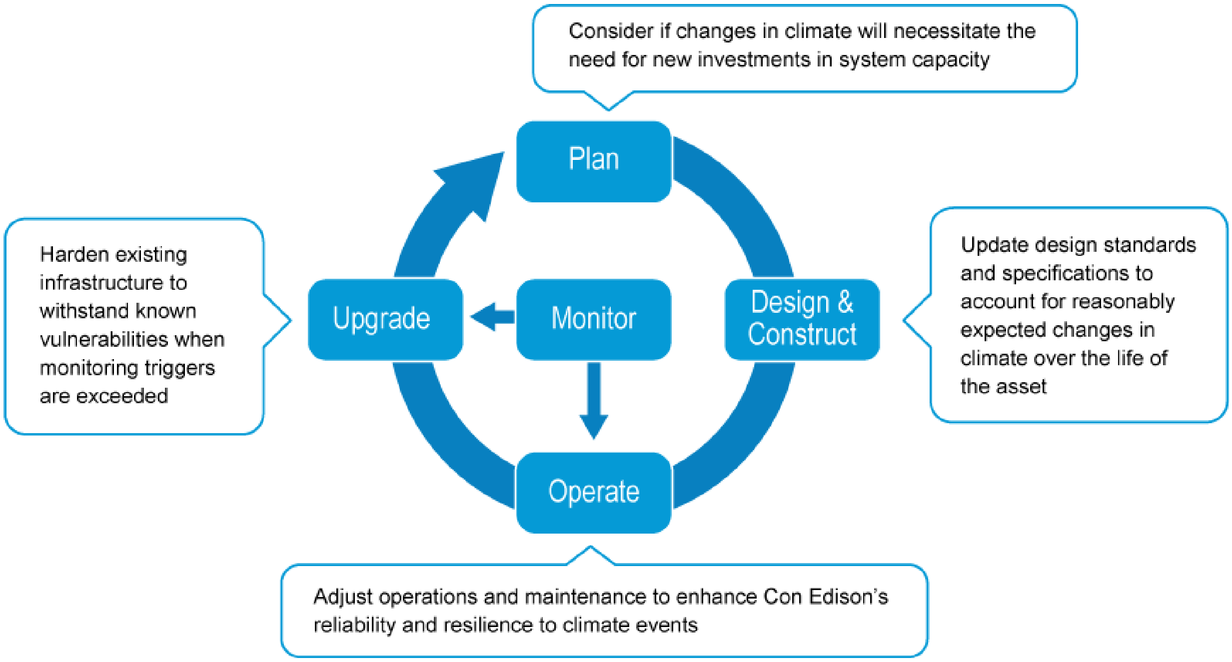
Under a changing climate, Con Edison will likely experience the increasing frequency and intensity of both gradual climate changes and extreme events. In response, the Study team developed a resilience management framework (Figure 12) to outline how a comprehensive set of adaptation strategies would mitigate future climate risks. The framework encompasses investments to better withstand changes in climate, absorb impacts from outage-inducing events, recover quickly, and advance to a better state. The "withstand" component of this framework prepares for both gradual (chronic) and extreme climate risks through resilience actions throughout the life cycle of assets. As such, many of the adaptation strategies identified in the following sections fall under the category of systematically bolstering Con Edison's ability to withstand future climate risks. Investments to increase the capacity to withstand also provide critical co-benefits, such as enhanced blue-sky functionality and the reliability of Con Edison's system. The resilience management framework facilitates long-term adaptation and creates positive resilience feedback so that Con Edison's system achieves better functionality through time. To succeed, each component of a resilient system requires proactive planning and investments.

**Figure 12** ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Investing in a more resilient system (blue line) provides benefits relative to a less resilient, or business-as-usual, system (red dashed line) before, during, and after an outage-inducing event. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.




“Withstand” entails proactively strengthening the system to mitigate and avoid climate change risks and increase the reliability of Con Edison’s system. “Withstand” investments are not necessarily a one-time event. Rather, the ability to withstand climate change must be integrated and revisited throughout the life cycle of Con Edison’s assets. Doing so requires changes in the planning, design, and construction of new infrastructure; ongoing data collection and monitoring; and eventually investing in the upgrade of existing infrastructure, using forward-looking climate information. This life cycle approach to considering climate change is captured in Figure 13. Across Con Edison’s electric, gas, and steam systems, planning for new investments in system capacity serves as a critical and strategic opportunity to integrate climate considerations. In addition, an important aspect of increasing the capacity of new investments to withstand changes in climate is maintaining strong design standards that account for gradual changes in chronic stressors and more frequent extreme events. However, since design standards do not apply to existing infrastructure, a strong monitoring program and signposts for additional adaptation investments could help ensure that Con Edison’s existing infrastructure remains resilient to climate change by informing adjustments to operations and potential needs for upgrades.

**Figure 13** ■ "Withstand" actions and investments must be revisited throughout the life cycle of Con Edison's assets.




"Absorb" includes strategies to reduce the consequences of outage-inducing events, since Con Edison cannot and should not harden its energy systems to try to withstand every possible future low-probability, high-impact extreme weather event. These actions, many of which Con Edison is already implementing, include operational changes to reduce damage during outage-inducing events and to protect exposed systems from further damage.

"Recover" aims to increase the rate of recovery and increase customers' ability to cope with impacts after an outage-inducing event. Such strategies build on Con Edison's Emergency Response Plans and Coastal Storm Plans. In addition, there is a role that Con Edison can play to increase customer coping and prioritize the continued functioning of critical services. Resilient customers are those who are prepared for outages and are better able to cope with reduced energy service—through measures such as having on-site energy storage, access to locations in their community with power, the ability to shelter in place without power, and/or prioritized service restoration for vulnerable customers.

"Advance" refers to building back stronger after climate-related outages and updating standards and procedures based on lessons learned. Even with proactive resilience investments, outage-inducing climate events can reveal system or asset vulnerabilities. Adjusting Con Edison's planning, infrastructure, and operations to new and future risks after an outage-inducing event, while incorporating learning, will allow for a more effective and efficient transition to greater resiliency. Con Edison has taken this approach in the past, including investing a billion dollars in storm hardening measures after Superstorm Sandy. Moving forward, restoring service following an outage-inducing climate event to a better adapted, more resilient state begins with effective pre-planning for post-event reconstruction. Where assets need to be replaced during recovery, having a plan already in place for selection and procurement of assets designed to be more resilient in the future can help to ensure that Con Edison is adapting to future extremes in a continuously changing risk environment.

Implementation of adaptation strategies throughout all of these phases will need to be adjusted over time to manage for acceptable levels of risk despite uncertainties about future conditions. The flexible adaptation pathways approach, described in further detail in the subsequent section, ensures the adaptability of adaptation strategies over time as more information about climate change and external conditions becomes available.

## All Commodities (Electricity, Gas, and Steam)

### Vulnerabilities

The Study team identified priority hazards for each of Con Edison's commodity systems (electric, gas, and steam) and found that several hazards were priorities across all three systems, although these hazards present unique vulnerabilities to the various assets within each system. The hazards common to all three systems are heat index, precipitation, sea level rise and storm surge, and extreme and multi-hazard events. These are discussed below. System-specific vulnerabilities are subsequently discussed in separate sections.

#### Heat Index

Worker safety may be a point of vulnerability if heat index values rise as projected. The Occupational Safety and Health Administration has set a threshold of 103°F for high heat index risk for people working under hot conditions. During the base period (1998–2017), there were 2 days per year with maximum heat greater than or equal to 103°F (but below 115°F). Under a lower emissions climate scenario (RCP 4.5 10$^{th}$ percentile), the 103°F threshold may be met 5 to 7 days per year by 2050; under a higher emissions scenario (RCP 8.5 90$^{th}$ percentile), this may occur 14 to 20 days per year by 2050. This poses a potential health threat to all Con Edison workers whose duties require outdoor labor.

Projected increases in heat index may also affect cooling equipment across Con Edison's systems, including the HVAC units for Con Edison buildings, air cooling towers for the electric system, and a water cooling tower for Con Edison's East River Steam Generating Plant. In order to supply sufficient cooling to its systems in 2080, Con Edison's HVAC systems will have to increase their capacity by 11% due to projected increases in dry bulb temperature. These systems have a roughly 15-year life span and therefore can be upgraded during routine replacements at an incremental cost of $1.3 million for 157 units. Similarly, Con Edison's cooling towers will have to increase their capacity by 30% by 2050. Cooling towers have a 20- to 35-year life span, allowing them to be upgraded during routine replacements at an incremental cost of $1.1 million for 19 cooling towers at 13 sites.

#### Precipitation

The Study team conducted an analysis of the physical and operational vulnerabilities of Con Edison's steam system, gas system, and transmission and substation components of the electric system. Findings indicated that all underground assets are vulnerable to flooding damage (i.e., water pooling, intrusion, or inundation) from heavy precipitation occurring over a short period of time. Specific vulnerabilities and their relevant thresholds vary significantly by commodity and, as such, are outlined in their respective sections.

### Sea Level Rise and Storm Surge

The Study team broke down evaluation of priority vulnerabilities related to sea level rise into two components.

The first component focuses on design standards for new infrastructure. The Study team assessed Con Edison's coastal flood protection standards for robustness to projected sea level rise. Con Edison's current design standard for coastal flood protections includes the FEMA 1% annual flood hazard elevation, 1 foot for sea level rise, and 2 feet of freeboard, which aligns with New York City's Climate Resilience Design Guidelines for critical infrastructure and water elevations that Con Edison experienced during Superstorm Sandy. Under high-end sea level rise (e.g., due to either rapid ice loss from the West Antarctic Ice Sheet corresponding to Kopp et al., 2017, or RCP 8.5 95th percentile projections corresponding to Kopp et al., 2014), the existing 1 foot sea level rise risk tolerance threshold could be exceeded by 2030; however, under more likely scenarios, the current threshold could be exceeded between 2040 and 2080.[12] The probability that sea level rise will exceed the 1-foot sea level rise risk tolerance by 2020 is under 10%; that increases to 65% to 70% by 2050, and to 100% by the 2080s.

The second evaluation component identified specific physical vulnerabilities of Con Edison's existing assets to impacts related to sea level rise, which are described by commodity below.

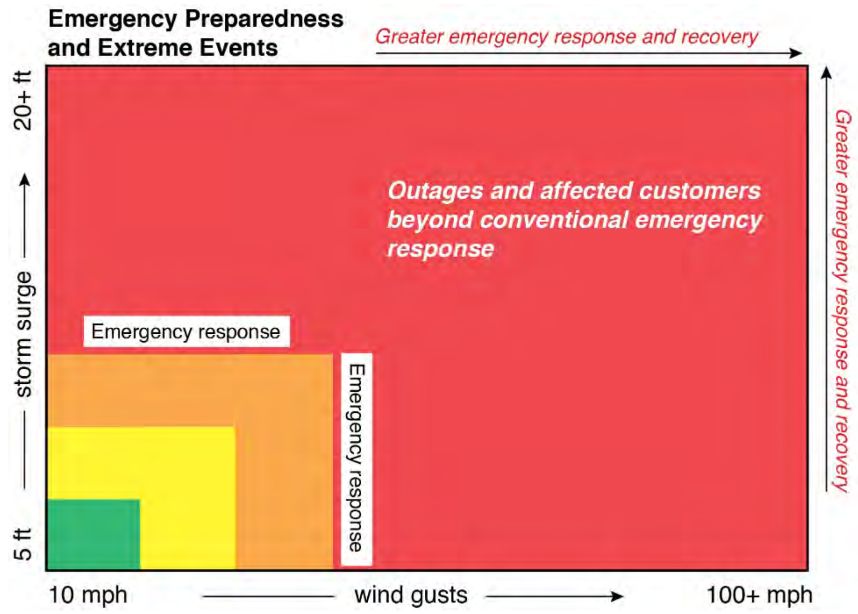
### Extreme and Multi-Hazard Events

Assets across all systems are vulnerable to possible damage from extreme event flooding. Storm surge driven by an extreme hurricane event (i.e., a Category 4 hurricane) has the potential to flood both aboveground and belowground assets. Specific asset damage varies by commodity and is outlined in the commodity-specific sections. In addition, flooding from ice-melt and snowmelt may cause significant damage to assets across all commodities, especially if the melt contains corrosive road salts.

On an operational level, increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts. Con Edison's extreme weather response protocols are specified in the company's hazard-specific Emergency Response Plans and Coastal Storm Plans for electric, steam, and gas systems. Con Edison's current "full-scale" response, which calls for all Con Edison resources and extensive mutual assistance, is initiated when the number of customers out of service reaches approximately 100,000. However, low-probability extreme events can increase customer outages and outage durations by an order of magnitude, outpacing current levels of emergency planning and preparedness, as shown in Figure 14.

[12] The sea level rise projections use a baseline year of 2000. For more details on these projections and how they relate to Con Edison's design standards, see Appendix 4.

**Figure 14** ■ Schematic diagram illustrating the increasing impacts during an extreme event (e.g., hurricane with extreme wind gusts and storm surge) that demands correspondingly large emergency response efforts that may exceed those experienced historically.




## Adaptation Measures to Address Vulnerabilities

Several adaptation measures help address vulnerabilities across Con Edison's electric, gas, and steam systems: improved monitoring systems and capabilities to support planning and decision making, emergency preparedness and full system recovery, and improved customer coping.

### Improved Monitoring Systems and Capabilities to Support Planning and Decision Making

Con Edison can collect updated and comprehensive data to further strengthen the resilience of its long-term plans and decision-making processes to climate change. Signposts guide planning and decision making, especially through informing the timing of implementation and the adjustment of adaptation measures, described in greater detail in the section below on Moving Towards Implementation.

As previously mentioned, it is important to have the latest information on climate variables and projections as the climate changes and the science improves. Monitoring local climate rates of change across the service territory can help Con Edison better track both changing conditions and potential points of vulnerability across its systems. Specific adaptation measures per commodity that are dependent on the monitoring of climate variable information are detailed in the respective commodity sections. In addition to information on climate variables, Con Edison will need to stay abreast of the latest climate science projections generated by expert organizations such as IPCC, NCA, and NPCC. The Study team suggests that Con Edison could revise its planning and decision-making processes at least every 5 years to incorporate updated climate science information.

### Emergency Preparedness and Full System Recovery

Con Edison should consider a range of adaptation strategies to increase capacity for an efficient preparedness and recovery process, as defined in Table 3.

**Table 3** ■ Emergency preparedness and system recovery adaptation strategies

| Adaptation Strategy | Measures |
|---|---|
| Strengthen staff skills for streamlined emergency response. | • Use technology to increase the efficiency of emergency response work crews.<br>• Review the Learning Center courses to ensure that crews are developing the skills required for emergency response.<br>• Incorporate supply shortages into emergency planning exercises. |
| Plan for resilient and efficient supply chains. | • Develop a resilience checklist for resilient sourcing.<br>• Have a plan already in place for selection and procurement of assets designed to be more resilient in the future.<br>• Ensure that parts inventories are housed out of harm's way and in structures that can survive extreme weather events.<br>• Standardize equipment parts, where possible. |
| Coordinate extreme event preparedness plans with external stakeholders. | • Continue coordination with telecommunication providers, including through joint emergency response drills.<br>• Continue and strengthen collaboration with the city to improve citywide design, maintenance, and hardening of the stormwater system. For example, improved drainage could alleviate the potential impacts of flooding and increase the effectiveness of adaptation measures in which Con Edison invests (e.g., drain hardening at manholes). |
| Incorporate low probability events into long-term plans. | • Continue expanding the Enterprise Risk Management framework to include lower probability extreme weather events and long-term issues (e.g., 20+ years).<br>• Conduct additional extreme weather tabletop exercises informed by the future narratives outlined in this report, and consecutive extreme weather events.<br>• Consider expanding the definition of critical facilities and sensitive customers. |
| Track weather-related expenditures. | • Con Edison's Work Expenditures Group could track expenditures, such as the cost of outages and repairs or customer service calls. Concurrently tracking climate and cost data will enable Con Edison to perform correlation analysis over time. |
| Update extreme event planning tools. | • Con Edison currently uses an internal Storm Surge Calculator (an Excel workbook that determines the flood measures to be employed for coastal assets based on a given storm tide level) to help plan for coastal flooding impacts. Con Edison could adjust inputs to this program to reflect the following:<br>– Updated storm surge projection information, using high-end forecasted surge<br>– Information from coastal monitoring, such as sea level rise and coastal flooding<br>• In addition, Con Edison could regularly revisit the definition of critical equipment so that the Storm Surge Calculator can best inform prioritization of equipment upgrades. |
| Expand extreme heat worker safety protocols. | • Implement safety protocols (e.g., shift modifications and hydration breaks) practiced in mutual aid work in hotter locations such as Florida and Puerto Rico.<br>• Examine and report on the levels of workers necessary to prepare for and recover from extreme climate events. |
| Improve recovery times through system and technology upgrades. | • Consider the use of drones and other technology (satellite subscription) or social media apps for damage assessment.<br>• Use GIS system to facilitate locating and documenting damage.<br>• Expand the use of breakaway hardware and detachable service cable and equipment. |

### Improved Customer Coping

Extreme events can present outsized risks compared to chronic events—risks that, in some cases, also extend to larger geographic areas. For example, impacts from hurricanes can overwhelm multiple facets of Con Edison's system and surrounding communities. Con Edison is positioned at the center of increasingly interconnected societal, technological, and financial systems, making it difficult and inefficient to evaluate risks solely on a component-by-component basis (Linkov, Anklam, Collier, DiMase, & Renn, 2014). Together, these factors necessitate different approaches to considering adaptation compared with climate changes for which probabilities are more easily assigned.

While the City of New York has primary responsibility for coordinating resident emergency response efforts, Con Edison can play a role in increased customer coping and resilience. This includes helping customers cope with reduced energy service if an extreme event leads to prolonged outages (e.g., supporting on-site energy storage, access to locations in the community with power, prioritized service restoration for vulnerable areas). Table 4 provides more specific adaptation strategies. Overall, Con Edison could consider expanding the definition of critical facilities and sensitive customers.

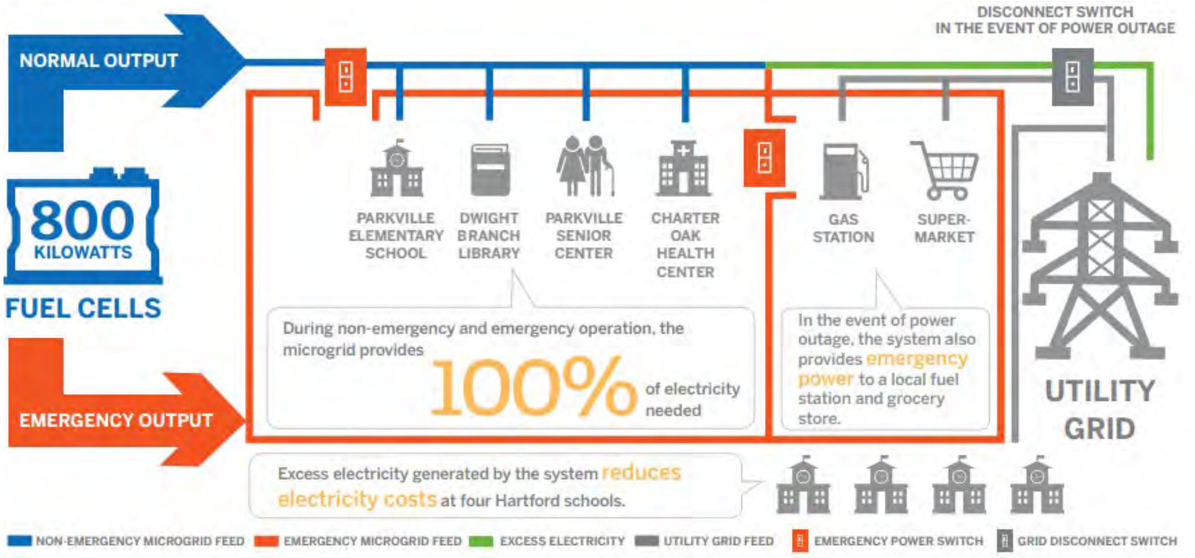
**Table 4** ■ Improved customer coping adaptation strategies

| Adaptation Strategy | Measures |
|---|---|
| Create resilience hubs (see below for more information). | • Use solutions such as distributed generation, hardened and dedicated distribution infrastructure, and energy storage so that resilience hubs can function akin to microgrids to provide a range of basic support services for citizens during extreme events.<br>• Continue to promote the pilot resilience hub at the Marcus Garvey Apartments in Brooklyn, using a lithium ion battery system, fuel cell, and rooftop solar to provide back-up power to a building with a community room that has refrigerators and phone charging.<br>• Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs.<br>• Use AMI capabilities to preserve service for vulnerable populations, if possible. |
| Invest in energy storage. | • Continue to enhance customer resilience through continued installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations.<br>• Continue to explore ways to help customers install, maintain, and make use of distributed energy resource assets for power back-up, self-sufficiency, and resilience purposes. |
| On-site generation | • Con Edison currently supports on-site generation for customers through programs such as rebate and performance incentives for on-site residential and commercial photovoltaic solar generation, incentives for behind-the-meter wind turbines, and incentives for combined heat and power projects that Con Edison currently facilitates in collaboration with the New York State Energy Research and Development Authority.<br>• On-site generation is a recommended approach for locations where resilience hubs may not be affordable or necessary.<br>• Con Edison could continue to encourage on-site generation for individual businesses and residential buildings. |
| Energy efficiency | • Support improved passive survivability, or the ability to shelter in place for longer periods of time, through enhanced energy efficiency programs.<br>• Continue to support energy efficiency programs and further expand its energy efficiency program portfolio to include additional incentives for energy-efficient building envelope upgrades. |

Resilience hubs are an emerging idea in resilience planning, which focus on building community resilience by creating a space (or spaces) to support residents and coordinate resources before, during, and after extreme weather events (Baja, 2018). A key requirement for a resilience hub is continued access to energy services. The objective of a resilience hub is to be able to provide a range of basic support services for citizens during extreme events. To accomplish this, resilience hubs may require a hybrid energy solution that includes multiple generation sources (e.g., solar and natural gas generation) and energy storage (i.e., batteries), plus dispatching controls, similar to the functionality of a microgrid. Figure 15 and Figure 16 demonstrate how a fuel cell-based microgrid can be used to power key community locations during normal operating conditions and during emergency events.

**Figure 15** ■ Fuel cell-based microgrid supplying energy to key community locations (Constellation Energy)


**Figure 16** ■ Diagram of microgrid operations during normal and emergency operations (Constellation Energy)



# Electric System

## Electric System Overview

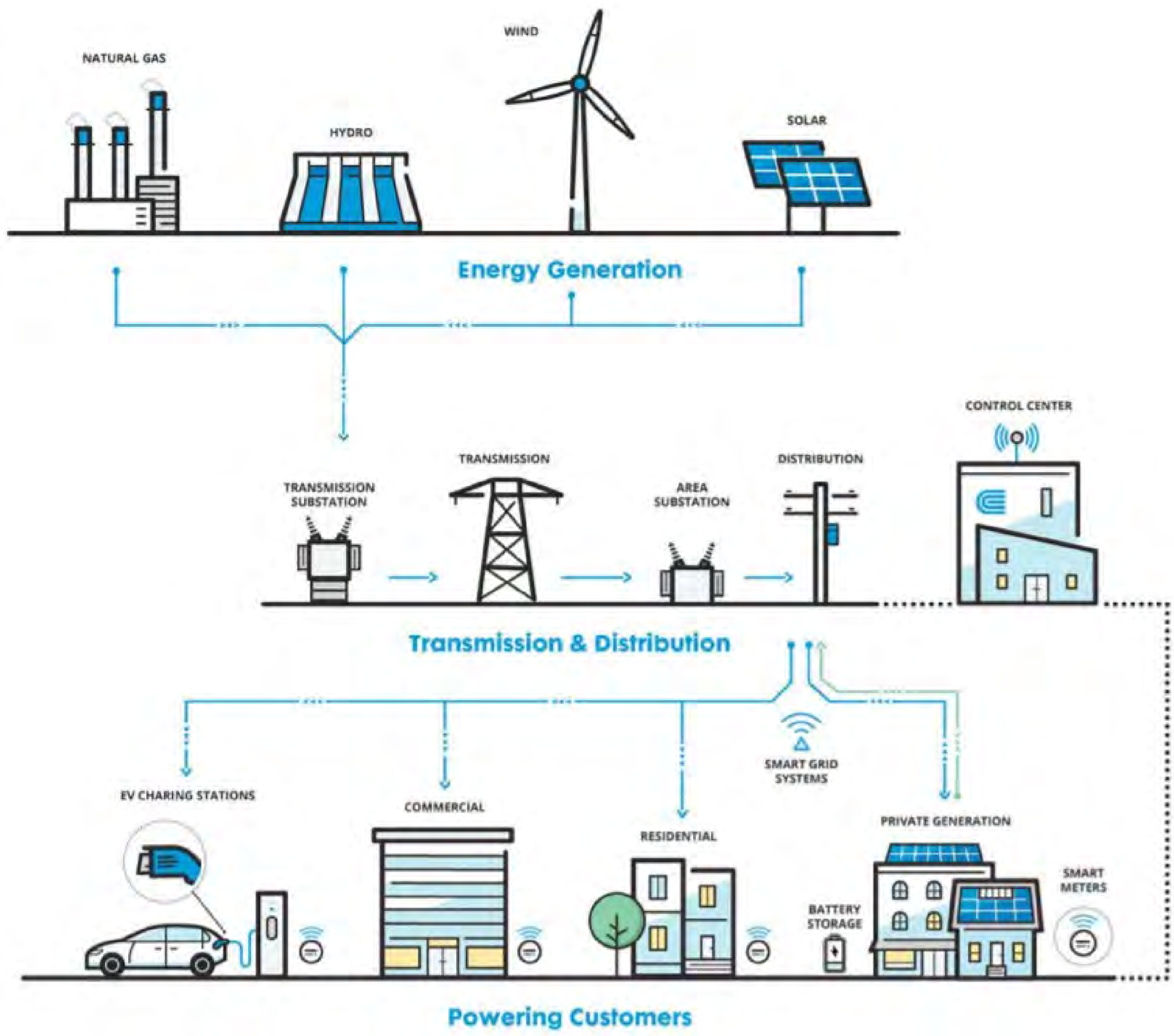
Con Edison's electric service territory includes both New York City and Westchester County, covering an area of 660 square miles and serving 3.3 million customers. Figure 17 depicts a schematic of the Con Edison electric system.

Con Edison's grid is a delivery system that connects energy sources to customers. While most electricity delivered is produced by large third-party generating stations, distributed energy resources also supply energy to the grid.

Energy produced by generating sources is delivered via the Con Edison transmission system, which includes 430 circuit-miles of overhead transmission lines and the largest underground transmission system in the United States, with 749 circuit-miles of underground cable. The system also includes 39 transmission substations. The high-voltage transmission lines bring power from generating facilities to transmission substations, which supply area substations, where the voltage is stepped down to distribution levels.

Con Edison has two different electric distribution systems—the non-network (primarily overhead) system and the network (primarily underground) system. The network system is segmented into independent geographical and electrical grids supplied by primary feeders at 13 kilovolts (kV) or 27 kV. The non-network system is designed using either overhead autoloops with redundant sources of supply, or 4-kV overhead grids arranged in a network configuration or as underground residential distribution systems designed in loop configurations.

**Figure 17** ■ Diagram of the Con Edison Electric System



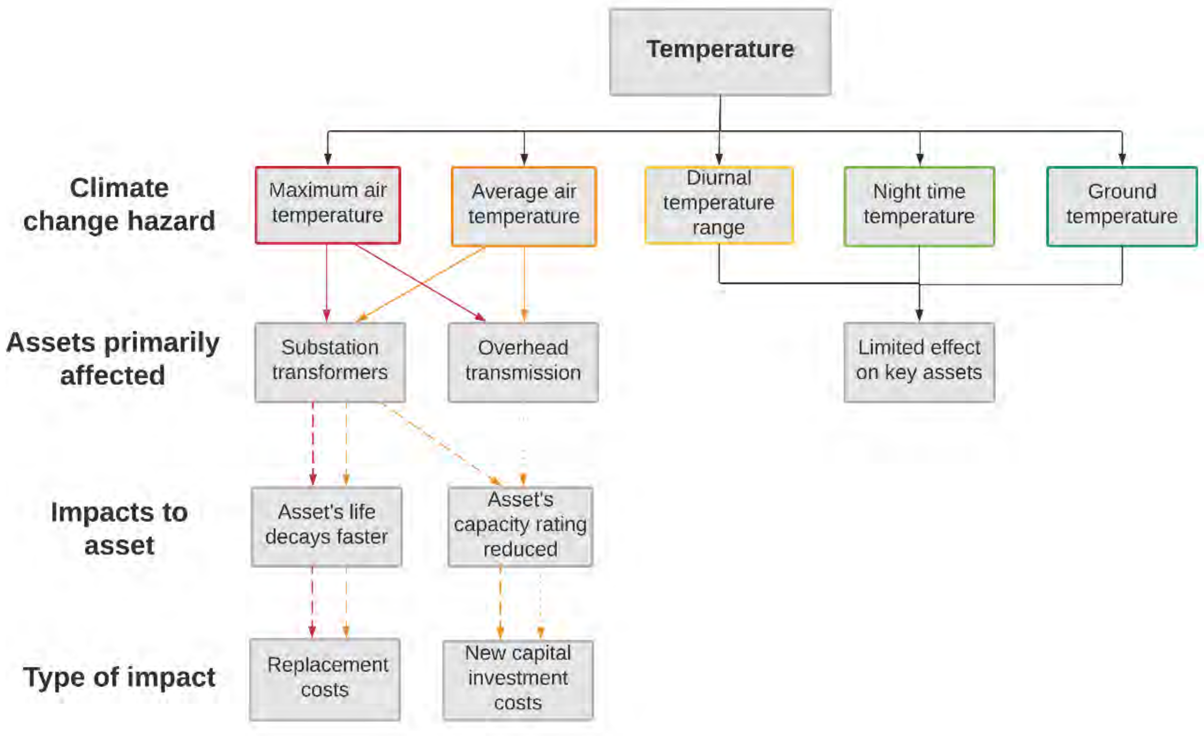

## Electric Vulnerabilities

Assets in the electric segment of Con Edison's business are most vulnerable to climate-induced changes in temperature/humidity and sea level rise. Both climate hazards have already shown their ability to bring about outages or damage assets and interrupt operations and carry the potential for future impacts. More information on specific vulnerabilities for these and other climate stressors is discussed below.

### Heat and Temperature Variable (TV)

The core electric vulnerabilities for increasing temperature and TV include increased asset deterioration, decreased asset capacity, decreased system reliability, and increased load. Figure 18 illustrates how temperature-related stressors, such as maximum and average air temperature, lead to impacts on the electric system.

**Figure 18** ■ Temperature-related impacts on Con Edison's electric system




### *Increased Asset Deterioration*

Increased average temperatures pose a threat to substation transformers. Within a substation, transformers are the asset most likely to be affected by projected higher temperatures since their ambient temperature design reference temperature is lower (i.e., 86°F) than that of most other assets.[13] Higher average and maximum ambient temperatures increase the aging rate of the insulation in transformers, resulting in decreased asset life.[14]

### *Decreased Asset Capacity*

Because an asset's internal temperature is the result of the ambient temperature in which it operates, as well as the amount of power it delivers, operating in an ambient temperature above the design reference temperature decreases the operational rating of the asset. However, derating the system due to increasing temperatures would effectively decrease the capacity of the system. When the capacity of the system is decreased, Con Edison must make investments to replace that capacity. The Con Edison system is currently designed with the capacity to meet a peak summer demand of more than 13,300 megawatts (MW). Based on projected temperature increases, capacity reductions in 2050 could range from 285 MW

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[13] Buses, disconnect switches, circuit breakers, and cables all have a design reference temperature of 104°F or higher.

[14] Not every excursion above the designed-for temperature will result in decreased service life. Two conditions must be met for the useful life of the transformer insulation to experience an increased rate of decay: (1) the ambient reference temperature rating must be exceeded, and (2) the transformer must be operating at the rated load, typically as a result of the network experiencing a single or double contingency.

to 693 MW for overhead transmission, switching stations, area station and sub-transmission, and network transformers.[15] This could potentially result in a capital cost of $237 million to $510 million by 2050.

The primary impact of increases in ambient temperatures on overhead transmission lines (assuming peak load) is increased line sag. Insufficient line clearance presents a safety risk should standard measures such as vegetation management not alleviate the risk. If standard measures cannot be applied, the lines would have to be derated and investments would be needed to replace the diminished capabilities of the line.

### *Decreased System Reliability*

Increases in TV-related events are expected to affect the electric network and non-network systems by decreasing reliability. Con Edison uses a Network Reliability Index (NRI) model to determine the reliability of the underground distribution networks.[16] Con Edison has set an NRI value of 1 per unit (p.u.) as the threshold over which reliability is considered unacceptable. Currently, there are no networks that exceed this standard.

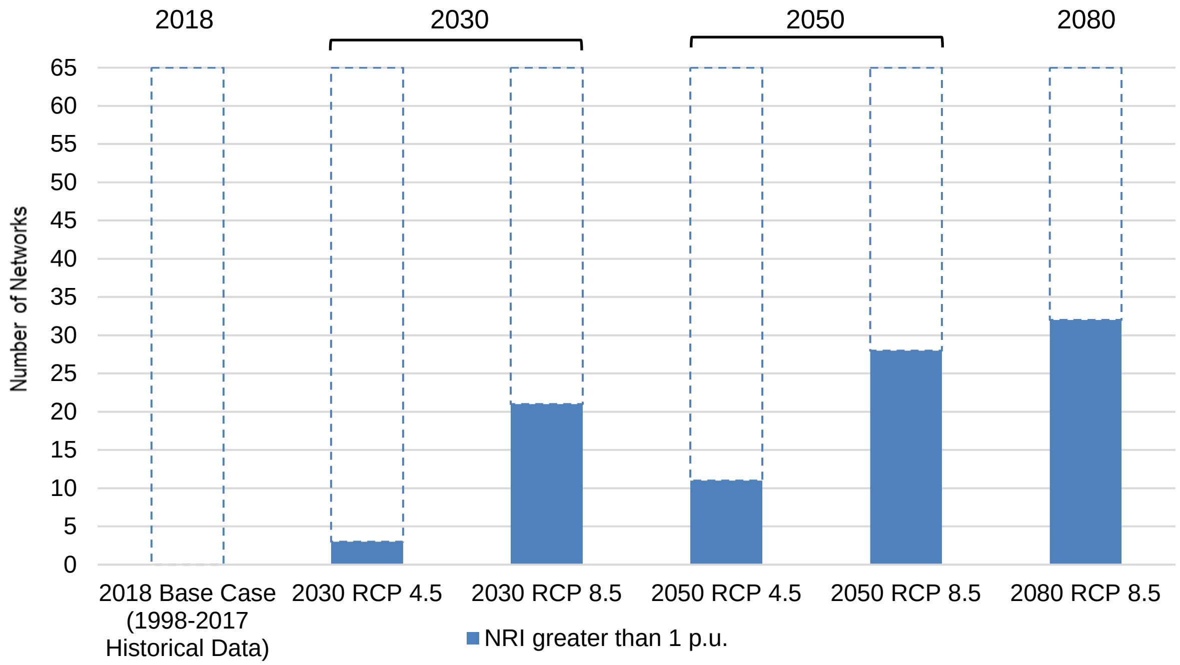
The Study team modeled how the NRI value of each network would change without continued investments in the system. The forward-looking NRI analysis found that with an increase in the frequency and duration of heat waves by mid-century, between 11 and 28 of the networks may not be able to maintain Con Edison's 1 p.u. standard of reliability by 2050, absent adaptation. Under the higher emissions scenario (RCP 8.5 90th percentile), projected impacts are relatively severe, even by 2030, with up to 21 total networks projected to exceed the NRI threshold by that year, absent adaptation (Figure 19). These deficiencies can be reduced by continuing to make investments to better withstand climate events, which Con Edison has done in the past through measures such as infrastructure hardening and added redundancy, diversity, and flexibility in power delivery. Such measures carry the co-benefit of improving blue-sky functionality and reliability.

Currently, Con Edison replaces paper-insulated, lead-covered (PILC) cables as an effective first line of defense against NRI increases. Con Edison is committed to continued investment in this measure, which will help reduce this heat-related vulnerability in the near term. The Study team also quantified the value of other measures to maintain network reliability, including innovative distribution designs and the use of distributed resources, which can be part of microgrids.

[15] The assumed decrease in capacity is 0.7% per °C (0.38% per °F) for substation power transformers, and 1.5% per °C (0.8% per °F) for overhead transmission conductors (Sathaye, 2013).

[16] NRI is a Monte Carlo simulation used to predict the performance of a network during a heat wave. The program uses the historical failure rates of the various components/equipment that are in the network, and through probability analysis determines which networks are more likely to experience a shutdown.

**Figure 19** ■ The number of networks above the NRI threshold of 1 p.u. under both climate scenarios for 2030, 2050, and 2080




The Study team also analyzed the impact of climate change on non-network reliability, which is measured in terms of the System Average Interruption Frequency Index (SAIFI).[17] The results indicate that the reliability of the non-network system is somewhat vulnerable to heat events; however, climate impacts would be negligible out to 2080. The average contribution to reliability from non-network autoloop feeder failures and 4-kV grid supply feeder failures due to increased temperatures would only contribute up to 8% of the maximum threshold SAIFI of 0.45 (i.e., a 0.035 increase in SAIFI in 2080) (New York Department of Public Service, 2018).

### *Increased System Load*

When temperature and humidity increase, demand for electricity for cooling also increases. Therefore, higher TV in the summer can cause higher peak loads. The Study team found an increase in peak load in 2050 of 6.9% to 19.2%, as compared to historical conditions. These projected changes in load are due only to the impact of changing TV, and do not take into consideration changes in other factors (e.g., population, increased air conditioning penetration). The Study team found a decrease in winter peak electric load.

Increases in load may require investments in system capacity to meet the higher demand. This cost could be between $1.1 billion and $3.1 billion by 2050. The 10- and 20-year load relief investment plans use asset ratings and load forecasts as key inputs, both of which include temperature as a factor. This combination of a greater demand and a decreased capacity to fill that need will likely warrant a revision to the load relief planning process in the future (Table 5).

[17] SAIFI is a measure of customer reliability. It is the average number of times that a customer is interrupted for 5 minutes or more over the course of 1 year.

**Table 5** ■ The combined impacts of increased load and asset capacity reduction in 2050

| Scenario | Total capacity under base and future temperature conditions (MW) | Incremental capacity reduction due to temperature | Peak load during current and future 1-in-3 events (MW) | Incremental load increase due to changes in TV | Total additional capacity needed under climate scenarios (MW) |
|---|---|---|---|---|---|
| Base Case 2050 | 13,300 | 0 | 13,525 | – | 0 |
| RCP 4.5 10th percentile 2050 | 13,015 | 285 | 14,949 | 1,424 | 1,709 |
| RCP 8.5 90th percentile 2050 | 12,607 | 693 | 16,491 | 2,966 | 3,659 |

### *Secondary Vulnerabilities*

The Study team identified additional heat and humidity-related vulnerabilities in Con Edison's system that were not flagged as priority vulnerabilities but nonetheless present risks.

- **Transmission system:** Con Edison's current transmission system is designed for the highest anticipated loads based on historical values. The Study team found that while load exceeded 90% of the peak load (presenting the possibility for thermal overload) on 1.5% of summer days historically, by 2050, this may increase to 5.2% of days under the RCP 8.5 90th percentile scenario. This shift in TV distribution may result in a small increase in the frequency of load drop from the transmission system.
- **Summer operations and voltage reductions:** When summer temperatures soar, Con Edison implements a set of procedures to avoid voltage and thermal stresses on the system. These procedures are triggered by a threshold (e.g., TV 86, which is the 1-in-3 peak load-producing TV). The Study team found that there could be a significant increase in the number of days with voltage reductions and summer work restrictions. However, if Con Edison continues to invest in the system to ensure operational capacity during the 2050 1-in-3 TV event, then there will be a drop in the frequency of voltage reductions and summer work restrictions, relative to today.
- **Corporate Emergency Response Plan:** Con Edison also uses TV thresholds to trigger elevated threat levels under its Corporate Emergency Response Plan (CERP). The Study team conducted an analysis to understand how the projected changes in TV will affect the exceedance of current CERP threat levels. The analysis indicates that TV conditions exceeding current thresholds will increase in both the lower (RCP 4.5 10th percentile) and higher (RCP 8.5 90th percentile) climate change scenario. The conditions for reaching a "Serious" threat level based on the current thresholds, for example, would increase from 0.4 days per summer, on average, to 1.8 days under RCP 4.5, and 12.8 days under RCP 8.5.
- **Volume forecasting:** Con Edison conducts volume forecasting to estimate the volume of energy the company needs to purchase, a portion of which is weather-sensitive. The calculation for this portion relies primarily on heating degree-days (HDDs) for the winter and cooling degree-days (CDDs) for the summer. The Study team estimated that Con Edison could experience an increase in summertime CDDs, which could result in the energy delivery increasing from 43,077 gigawatt-hours (GWh) in 2050 under the base case to 43,685 GWh under the RCP 4.5 scenario (a 1.4% increase), and to 45,394 GWh under the RCP 8.5 scenario (a 5.4% increase). The Study team found a less significant decrease in HDDs due to climate change.

### Sea Level Rise

RCP 4.5 and RCP 8.5 projections indicate that sea level rise may exceed Con Edison's current design standard for coastal flood protection (i.e., a 100-year storm with 1 foot of sea level rise and 2 feet of freeboard) between 2030 and 2080. The Study team analyzed the exposure of Con Edison's assets to 3 feet of sea level rise (i.e., the 2080 RCP 8.5 83rd percentile sea level rise projection), keeping the other elements of Con Edison's existing risk tolerance constant (i.e., a 100-year storm with 2 feet of freeboard). By summing the freeboard and sea level rise values, this equates to FEMA's 100-year floodplain elevation plus 5 additional feet.

Of the 324 electric substations (encompassing generating stations, area substations, transmission stations, unit substations, and Public Utility Regulating Stations [PURS]), 75 would be vulnerable to flooding during a 100-year storm if sea level rose 3 feet. Three of these potentially exposed substations would only require minimal modifications to protect them, 16 would require an extension of existing protections, eight would require a new protection approach (i.e., the existing protections cannot be extended), and 48 do not have existing protections because they are outside of the floodplain. Hardening all these substations is estimated to cost $636 million.

### Precipitation

The Study team found that substations, overhead distribution, underground distribution, and the transmission system are most at risk for precipitation-based hazards.

Substations may experience an overflow of water from transformer spill moats, which could release oil-contaminated water within the substation. However, the risk of such an event is low, as transformer spill moats are built at a level that is robust to all but a severe and highly improbably conjunction of events.[18]

The transmission and overhead distribution systems are both vulnerable to the accumulation of radial ice, which can build up on lines and towers during winter precipitation events. In extreme scenarios, accumulation of radial ice can result in unbalanced structural loading and subsequent transmission line failure, especially when accompanied by heavy winds (Nasim Rezaei, Chouinard, Legeron, & Langlois, 2015). Con Edison's current system meets the National Electrical Safety Code standard for radial ice and is robust to ice accumulation. It is uncertain whether climate change will increase or decrease the intensity of future icing events.

The underground distribution system is vulnerable to flooding and salt runoff from snowfall and ice events. Flooding can damage non-submersible electrical equipment. This risk is mitigated through Con Edison's designs: All underground cables and splices operate while submerged in water, and all underground distribution equipment installed in current flood zones (and all new installations) are submersible. Snowfall and ice require municipalities to spread salt on roads, which eventually seeps into the ground with runoff water. Road salt can degrade wire insulation and lead to insulation burning and arcing, potentially causing safety concerns and customer outages. It is currently unclear how salting frequency will change over time.

### Extreme Events

Hurricanes and nor'easters present physical risks associated with heavy winds, precipitation, and flooding, which can lead to widespread system outages and, at worst, physical destruction. During hurricanes, wind stress and windblown debris can lead to tower and/or line failure of the overhead transmission system

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[18] In accordance with New York State code and federal Spill Prevention, Control, and Countermeasure recommendations, Con Edison's transformers are protected by moats designed to hold water from a 6-inch, 1-day storm event, in addition to the gallons of oil that may be released during a spill event and a further 50,000–60,000 gallons of fire suppression fluid. Based on this standard, Con Edison's substation transformer moats are robust to 6 inches of rain during a catastrophic emergency, and significantly more than that at all other times.

and damage overhead distribution infrastructure, which could cause widespread customer outages. Intense rain during hurricanes can also flood substations, which may cause an overflow of oil-contaminated water from transformer spill moats. A Category 4 hurricane could very likely lead to outages for more than 600,000 non-network customers and more than 1.6 million network customers.

During nor'easters, accumulation of radial ice can cause tower or line failure of the overhead transmission system. Similarly, snow, ice, and wind can damage the overhead distribution system. Indirectly, salt put down by the city to contend with snow and ice accumulation on roads could infiltrate the underground distribution system, causing arcing and failure of underground components.

Extreme heat waves present a range of effects that can contribute to failures, including a lower ampacity rating while increasing load demand, causing cables and splices to overheat, transformers to overheat, and transmission and distribution line sag. Distribution network component failures can cause Con Edison to exceed the network reliability design standard. Greater line sag can lead to flashovers and line trips.

## Adaptation Options for the Electric System

### Withstand

In the short term, Con Edison can work to address the vulnerabilities of the electric system by integrating climate hazard considerations into planning, collecting data on priority hazards, and updating design strategies.

There are several opportunities to integrate climate change data into planning processes. For example, Con Edison could integrate climate change projections into long-term load forecasts, consult utilities in cities with higher temperatures to refine the load forecast equation for high TV numbers, and develop a load relief plan that integrates future changes in temperature and TV into asset capacity and load projections. During load relief planning, Con Edison could also consider whether extreme events may shift the preferred load relief option—frequent extreme heat could reduce the effectiveness of demand response programs. For the transmission system, Con Edison could integrate considerations of climate change into the long-range transmission plan. For the distribution system, Con Edison could integrate climate projections into NRI modeling and install high-reliability components,[19] as needed.

Given the potential risks that temperature and heat waves pose to the electric system, the Study team suggests that Con Edison could collect data on these hazards to build greater awareness of their impacts to the system, as well as to monitor for signposts that would trigger additional action. Specifically, Con Edison could:

[19] System components vary in their reliability. For example, PILC cable performs more poorly than solid dielectric cable.

- Install equipment capable of collecting, tracking, and organizing temperature data at substations to allow for location-specific ratings and operations.
- Make ground temperature data more accessible and track increases over time.
- Expand monitoring and targeting of high-risk vegetation areas.
- Continue to track line sag and areas of vegetation change via light detection and ranging (LiDAR) flyovers to identify new segments that may require adaptation.

These data could be used to routinely review asset ratings in light of observed temperatures. Con Edison could also incorporate heat wave projections into reliability planning for the network system.

Hurricanes are another priority hazard for the electric system and therefore warrant robust planning tools that capture potential changes in climate. Con Edison could complement their existing model used to predict work crews required to service weather-driven outages with an updated model that better resolves extreme weather events and extreme weather impacts on customers in the service territory.

Design standards are a way to help standardize resilience by ensuring that new assets are built to withstand the impacts of climate change hazards. The Study team suggests a variety of design standards:

- **Temperature:** Standardize ambient reference temperatures across all assets for development ratings.
- **Precipitation:** Update precipitation design standards to reference National Oceanic and Atmospheric Administration (NOAA) Atlas 14 for up-to-date precipitation data. Consider updating the design storm from the 25-year precipitation event to the 50-year event to account for future increases in heavy rain events.
- **Sea Level Rise:** Revise design guidelines to consider sea level rise projections and facility useful life. Continue to build to the higher of the FEMA + 3′ level and the Category 2 storm surge levels at new-build sites, as is current practice. Add sea level rise to the Category 2 maps to account for future changes and a greater flood height/frequency.

In addition to these systematic approaches, Con Edison can also help the electric system better withstand climate hazards through asset-specific physical adaptation measures, when needed. Table 6 illustrates these physical options.

**Table 6** Potential physical adaptation options for electric assets

| Main Hazard(s) | Vulnerable Assets or Plan | Adaptation Option | Implementation Timeframe | Signpost or Threshold |
|---|---|---|---|---|
| Temperature | Grid modernization | Continue to invest in grid modernization to increase resilience to climate change through new technology and increased data acquisition. Efforts include distribution automation, grid-edge sensing (environmental, AMI), asset health monitoring, conservation voltage optimization, and targeted system upgrades. | Continuous | Change in ambient operating temperatures, including changes in science-based projections |
| Heat Waves | Network system, which may experience reduced reliability (and therefore increased NRI) due to heat waves | Complete PILC cable replacements. | 2030 | Increased frequency or duration of heatwaves |
| | | Continue implementing load relief strategies to keep NRI ratings below 1. Options include:<br>• Split the network into two smaller networks.<br>• Create primary feeder loops within and between networks.<br>• Install a distribution substation.<br>• Incorporate distributed energy resources and non-wire solutions.<br>• Design complex networks that consider combinations of adaptation measures. | Continuous | NRI value over 1 p.u. |
| | Non-network distribution system | Maintain non-network reliability in higher temperatures by implementing the following:<br>• Autoloop sectionalizing<br>• Increased feeder diversity | 2080 | Forecasted System Average Interruption Frequency Index (SAIFI) ratings (incorporating climate change projections) above established thresholds |
| | Overhead transmission | Replace limiting wire sections with higher rated wire to reduce overhead transmission line sag during extreme heat wave events. Alternatively, remove obstacles or raise towers to reduce line sag issues. | Continuous | Increased incidence of line sag; higher operating temperatures |
| | | Explore incorporating higher temperature-rated conductors. | 2050 | Existing asset replacement |
| | Area and transmission substation transformers | Undertake measures that contribute to load relief, such as energy efficiency, demand response, adding capacitor banks, or upgrading limiting components, such as circuit breakers, or disconnect switches and buses. | 2030/2050 | Ambient temperatures exceeding asset specifications |
| | | Gradually install transformer cooling, or replace existing limiting transformers within substations. | 2050/2080 | Ambient temperatures exceeding asset specifications |
| Precipitation | Substations | Harden electric substations from an increased incidence of heavy rain events by doing the following:<br>• Raising the height of transformer moats<br>• Installing additional oil-water separator capacity<br>• Increasing "trash pumps" behind flood walls to pump water out of substations | 2080 | Changes in the 25-year return period storm |
| | Transmission and overhead distribution | Underground critical transmission and distribution lines. | 2080 | Increased incidence of icing |

| Main Hazard(s) | Vulnerable Assets or Plan | Adaptation Option | Implementation Timeframe | Signpost or Threshold |
|---|---|---|---|---|
| | Underground distribution | Retrofit ventilated equipment with submersible equipment to eliminate the risk of damage from water intrusion. | 2050 | Expanded area of precipitation-based flooding; better maps of areas at risk for current and future precipitation-based flooding |
| | | Reduce the incidence of manhole events due to increased precipitation and salting by doing the following:<br>• Expanding Con Edison's underground secondary reliability program<br>• Accelerated deployment of vented manhole covers<br>• Replacement of underground cable with dual-layered and insulated cable, which is more resistant to damage<br>• Installation of sensors in manholes to detect conditions indicating a potential manhole event | 2050 | Increase in the City's use of salt over the winter period; increased rate of winter precipitation |
| Hurricanes | Overhead transmission | Continue to expand existing programs to reinforce transmission structures; address problems with known components. | Continuous | Increased frequency/severity of heavy winds; existing asset replacement |
| | Overhead distribution | Invest in retrofits for open wire design with aerial cable and stronger poles. | 2080 | Increased frequency/severity of heavy winds; existing asset replacement |
| | | Underground critical sections of the overhead distribution system to ensure resilience against hurricane force winds and storm surge. | 2080 | Increased frequency/severity of heavy winds |
| Nor'easters | Overhead transmission and distribution | Continue to expand programs to reinforce transmission and distribution structures and expand the number of compression fittings used to address weak points in transmission lines. | Continuous | Increased incidence of icing; existing asset replacement |
| | Underground distribution | Upgrade high failure rate components. | Continuous | Increased frequency/severity of nor'easter events |

Of course, it is neither practical nor feasible for Con Edison to build resilience to the point that its electric system can fully withstand the impacts of all climate hazards. The Study team thus suggests that Con Edison consider the following strategies to help the electric system better absorb and recover from impacts:

### Absorb

- **Temperature:** Increase capabilities to provide flexible, dynamic, and real-time line ratings.
- **TV:** Routinely update voltage reduction thresholds and hands-off thresholds to account for changes in climate and the changing design of the system.
- **Hurricanes:** Continue to explore and expand operational measures to increase the resiliency of the overhead distribution system by increasing spare pole inventories to replace critical lines that are compromised during extreme weather events.
- **Heat waves:** Stagger demand response consecutive event days across different customer groups to increase participation; ensure that demand response program participants understand the purpose/cause of the event; use technology to more efficiently regulate load/use AMI to rapidly shed

load on a targeted network to help ensure that demand does not exceed supply; and continue installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations.

**Recover**

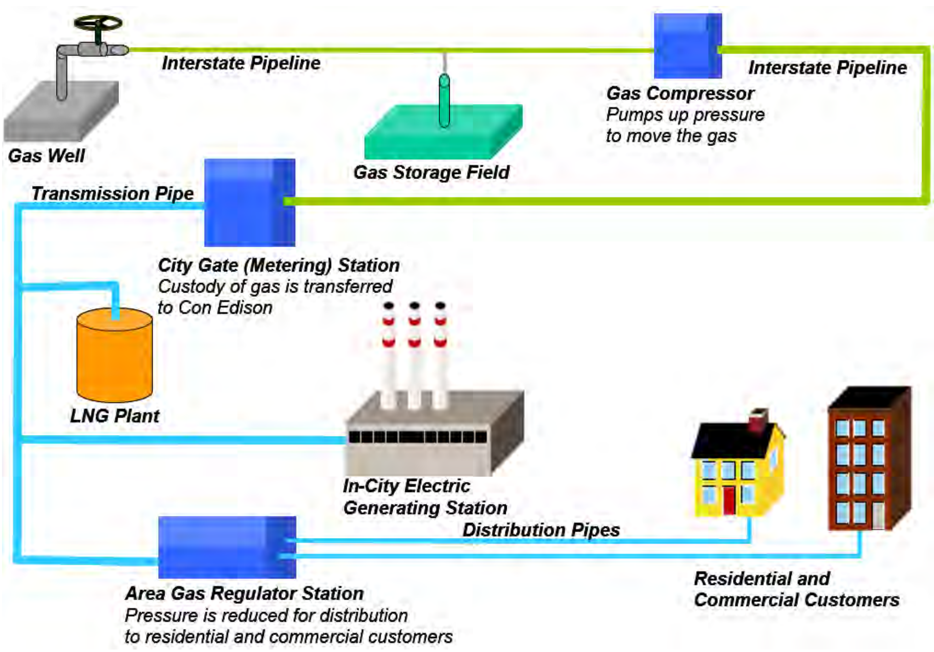
- **Heat waves:** Continue to actively engage forward-looking technologies to improve extreme recovery time for distribution systems, such as automated splicing systems to reduce feeder processing times.
- **Extreme events:** Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs; support increasing the percentage of solar/other distributed generation projects to allow for islanding; encourage on-site generation for individual businesses and residential buildings; and increase the use of LiDAR and drones to assess damage and reduce manual labor.

## Gas System

### Gas System Overview

Con Edison's gas service territory covers Manhattan, Bronx, Westchester, and parts of Queens. Con Edison serves approximately 1.1 million firm customers and 900 large-volume interruptible customers who can alternate fuel sources. The natural gas system consists of more than 4,359 miles of pipe transporting approximately 300 million dekatherms (MMdt) of natural gas annually. About 56% of the system operates at low pressure, 11% operates at medium pressure, and 33% operates at high pressure. Figure 20 depicts the Con Edison natural gas delivery chain.

**Figure 20** ■ Con Edison natural gas delivery chain



## Gas Vulnerabilities

Most of Con Edison's gas assets are underground, and gas load peaks in the winter rather than in the summer, which means that gas assets are less likely to be damaged by subaerial extreme events, such as heat waves, lightning, and strong winds. As discussed in Con Edison's Post Sandy Enhancement Plan, Con Edison's gas assets are most vulnerable to underground water intrusion caused by flooding, and thus projected increases in the frequency of heavy precipitation and downpours, sea level rise and storm surge, and hurricanes and nor'easters pose a significant risk (Con Edison, 2013).

Water intrusion can occur if underground water enters gas pipes or mains and may result in a drop in pressure and lead to scattered service interruptions; low-pressure segments of the system and cast iron pipes are particularly vulnerable to this risk. In addition, pipe sections near open-pit construction projects may also be more vulnerable, because open excavation work can create opportunities for water intrusion if flood protection measures are not consistently used. Con Edison has already developed operational protocols that require crews working on open excavation sites to secure them to minimize water intrusion risk.

Water intrusion into gas regulators through aboveground vents may also cause damage. This intrusion could lead to water sitting on top of the diaphragm that allows each regulator to function and exerting additional pressure on the diaphragm that could, in turn, over-pressurize the regulator. Over-pressurized gas flowing through a system designed for lower pressure gas increases the possibility of tearing leaks in distribution piping, and in the worst-case scenario, could blow out pilot lights.

For the gas distribution system to function at full capacity and to be able to provide customers with desired gas supply, Con Edison must keep gas moving through the system at the intended flow rate, or pressure level, of each system segment. Once water enters the gas system, it is difficult to pinpoint the location and remove the water, which can increase the durations of resulting service interruptions.

Con Edison is currently undertaking several measures to manage underground water intrusion:

- Using drip pots to collect water at low points in the system (approximately 8,000 are currently in place)
- Developing a program to better prioritize gas infrastructure replacements. Remote sensors and machine learning could identify leak-prone areas to prioritize for upgrades intended to mitigate increasing precipitation risks in the face of climate change
- Developing a drip pot remote monitoring program using sensors, which would increase the efficiency of periodic emptying of drip pots and reduce the effort needed to monitor drip pots during the period of planned pipe replacement
- Shifting toward constructing and repairing infrastructure with more leak-resistant equipment, when possible

A climate change-driven increase in the frequency and intensity of flood events, such as heavy rain events or snow events followed by rapid snow melt, or coastal storm surge, may elevate the risk of water infiltration into the low-pressure gas system. The precipitation threshold currently used as a benchmark for monitoring and emptying drip pots is ½ inch of rain in 24 hours. Under the RCP 8.5 scenario, this threshold is projected to be exceeded 37 days per year in Central Park by the latter part of the century, which is nearly 20% more than the 31 days observed over the baseline period.

Low-probability, high-impact extreme events may also include heavy rainfall and storm surge that could increase the risk of water entering the distribution system. An increase in the frequency and intensity of extreme events may make water infiltration into the gas distribution system more likely. Con Edison's gas system has established criteria to ensure that new equipment, such as gas regulator line vents, is resilient against a 100-year storm and 1 foot of sea level rise. After Superstorm Sandy, Con Edison upgraded two regulator stations to meet this standard. The Study team determined that to protect regulator stations against 3 feet of sea level rise, Con Edison would need to update 32 regulator stations, at a cost of $13.8 million.

The gas transmission system is vulnerable to cold snaps associated with nor'easters, when temperatures can drop below 0°F for multiple days. Transmission system capacity is designed to meet demand projected for weather conditions at or above 0°F. Temperatures below that threshold may increase demand to a level that exceeds system capacity; in such an event, system pressure may decrease, resulting in customer service loss.

In a generally warmer climate, the gas sector could experience significant decreases in winter energy sales for heating. There could be up to a 33% decrease by 2050 and a 49% decrease by 2080. Similarly, under the RCP 8.5 scenario, winter gas peak load is projected to decrease by 144 MMdt in 2050, compared to the base case.

## Adaptation Options for the Gas System

In addition to Con Edison's existing efforts, the Study team identified several additional adaptation options that the company could consider. Some measures proposed, such as remote information monitoring and analysis, address vulnerabilities in operations and planning processes. Most measures proposed address physical vulnerabilities (see Table 7), which fall within the "withstand" adaptation category.

In the short term, Con Edison could focus on expanding its monitoring capabilities, particularly through programs that use machine learning and remote monitoring to identify vulnerable areas of the distribution system, and remote drip pot monitoring sensors.

To account for changing temperatures, Con Edison could integrate climate change data on changes in the winter gas TV into gas volume and peak load forecasting so that the company is continuously planning for future changes in climate.

To address physical risks to existing infrastructure, Con Edison may need to invest in the system at strategic points in time, as described in Table 7.

Distribution system measures focus on minimizing the risk of flood water entering and depressurizing gas mains and pipes, and measures to more easily re-elevate pressure if water does enter the system.

Adaptation measures identified to address transmission system vulnerabilities primarily focus on diversifying the system and strengthening load management when capacity is constrained.

**Table 7** ■ Physical adaptation options for gas commodities

| Hazard | Asset | Adaptation Option | Implementation Timeframe | Signpost or Threshold |
|---|---|---|---|---|
| Extreme Hurricane (Category 4) | Transmission System | Procure additional compressed natural gas tank stations. | Designing for a future Category 4 hurricane | Increased frequency and severity of storms that could cut supply, including from science-based projections |
| | Gas Regulators | Install vent line protectors, extend vent lines and posts, seal all penetrations, and/or elevate key electric and communications equipment to protect vent lines. | 2050 | When sea level rise exceeds 1 foot, or if flooding is reported and the regulators do not have vent line protectors |
| | Distribution System | Continue targeted Main Replacement Program (planned completion by 2036) to harden gas mains against depressurization by water intrusion or other concerns. | ~2030 (goal to complete program by 2036) | Increase in flooding events |
| Extreme Nor'easter | Transmission System | Construct additional gate stations. | Designing for a future worst-case nor'easter | More frequent or intense cold spells that drop temperatures below the design threshold for consecutive days and threaten supply |
| | | Build larger and/or additional transmission mains. | | |
| | | Create ties between mains to diversify the transmission system. | | |
| | | Install remote operated valves to more efficiently isolate load for load management (temporarily disconnecting gas customers) during peak events. | | |

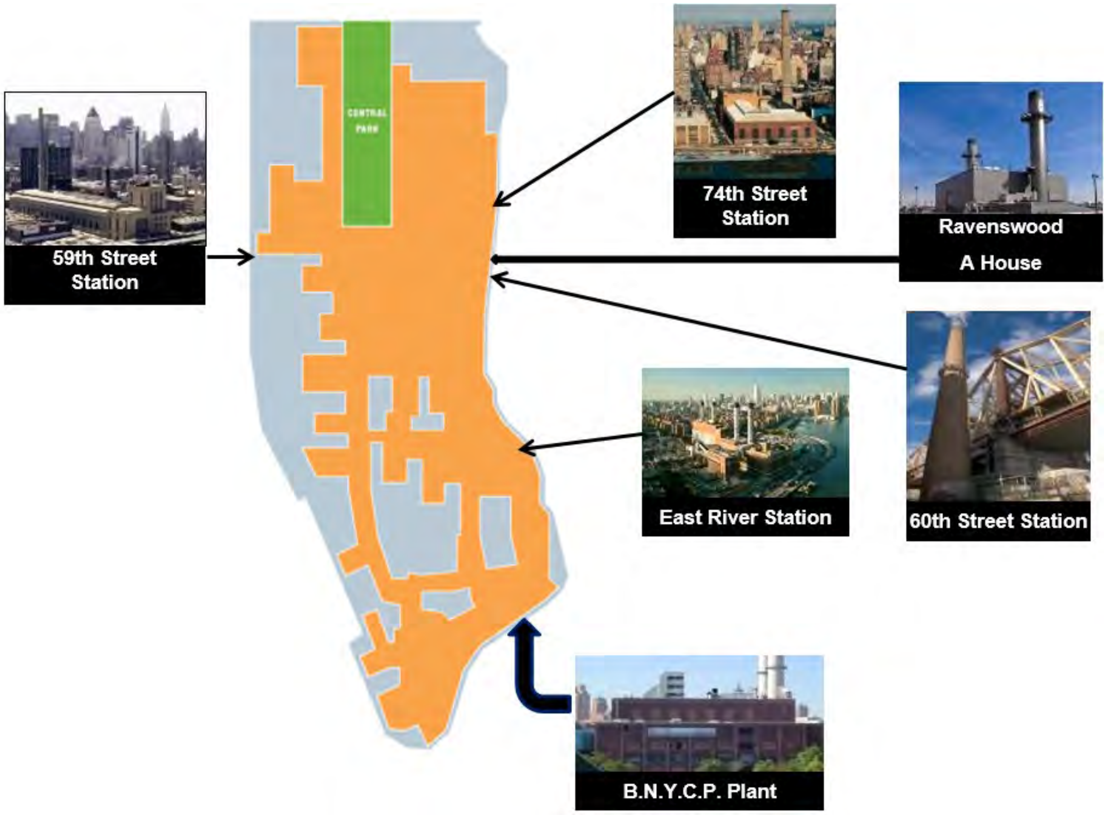
In addition, given the increasing potential for extreme events, Con Edison could consider distribution system resilience options such as exploring and implementing ways to elevate system pressure in low-flow conditions.

## Steam System

### Steam System Overview

Con Edison's steam system provides service to more than 3 million Manhattan residents (including approximately 1,720 metered customers) south of 96th Street. Total system capacity is about 11,676 thousand pounds per hour (Mlb/hr). The distribution system is comprised of a continuous network of pipes (steel main pipes and steel and brass service and condensate piping)—in aggregate, about 105 miles of piping. The pipes' physical location is directly correlated with the locations of generation sources and regional customer demand. Figure 21 shows the locations of several steam system assets.

**Figure 21** ■ Key assets included in the Con Edison steam system




## Steam Vulnerabilities

Like the gas system, much of Con Edison's steam system is underground, and steam is also a winter-peaking rather than a summer-peaking commodity. As such, steam generation and distribution assets are generally less prone to damage by shifts and extremes in temperature, humidity, and wind, and more vulnerable to flooding, which may be caused by increased precipitation, coastal inundation, snow melt, or storm surge in extreme events. Severe flooding impacts, such as broken distribution pipes and damaged steam generation stations, can take significant time to repair, further increasing the duration of customer impacts.

Increased frequency and intensity of precipitation events may increase the vulnerability of steam system manholes to "water hammer" events. When a high volume of water collects around a manhole, steam in the pipes underneath may cool and condense. Interaction between steam and the built-up condensate may cause a rupture in a steam pipe. One such water hammer event occurred in 2007 when a steam pipe at Lexington Avenue and 41st Street exploded during a period of heavy rainfall (Figure 22). Con Edison responded to that event by implementing a precautionary rain event threshold. If more than ¾ inch of rain is forecasted to fall within 3 hours, Con Edison will begin to proactively monitor and address flooding before it can cause a water hammer event. The key measure used to address flooding to prevent water hammer events is pumping water out of manholes and into the city sewer. In turn, Con Edison's capacity to manage flooding events that threaten steam generation and distribution assets depends on the capacity of the city's stormwater system to handle high volumes of water that Con Edison may need to pump away from assets under a changing climate.

Steam generation and distribution system assets are also vulnerable to projected increases in sea level and coastal inundation. Five out of six steam generating plants would be exposed to a 100-year storm if sea level rose by 3 feet. If water enters the steam generation system, it can degrade plant capacity or force unit or plant outages. Significant damage to steam generation systems would likely require long repair times, which could increase the duration of customer impacts. Hardening several of the generating stations to a higher level of protection would be difficult and costly. For example, at the East River Generating Station, raising mechanical equipment would require significant and costly alterations to the hydraulics of the steam system. Similarly, at East 13th Street, flood waters associated with a 100-year storm and 3 feet of sea level rise would reach the tertiary bushings on some 345-kV transformers, resulting in arcing and critical failure of the unit. The total estimated cost to harden the five steam generation plants against a 100-year storm and 3 feet of sea level rise is $30 million.

**Figure 22** ■ 2007 steam pipe explosion

Con Edison has adopted storm hardening measures to protect the steam system in response to recent storms such as Superstorm Sandy. Those measures include developing location-specific plans and drills in preparation for storms, implementing physical hardening measures at steam generating stations, protecting critical equipment by waterproofing or relocating it, installing a new steam main to ensure that hospitals receive continued service, and introducing isolation valves in strategic locations to reduce the number of customers impacted by flooding in future extreme events. Because isolating steam lines is key to managing flooding impacts, Con Edison considers several potential flood sources (e.g., rainfall deluges, storm tides, water main breaks) when evaluating hardening options, and periodically reviews and updates both operational and physical risk mitigation strategies. The company is also investing in steam system resilience through measures such as waterproofing system components in the normal course of upgrades, prioritizing hardening steam mains by prior flooding issues (fewer than 10 of the original 86 locations identified are still vulnerable), and using remote monitoring to monitor manhole water level and steam trap operation (a system is currently under design and expected to be operational by 2021).

Extreme and multi-hazard events could also increase the vulnerability of the steam distribution system to salt damage and flood damage. During nor'easters and extreme ice storms, the City of New York and jurisdictions in Westchester County conduct widespread street-salting operations to mitigate ice build-up on roads and sidewalks. Rapid melt after nor'easters and extreme ice storms can lead to an influx of salt-saturated runoff into manholes, in turn causing equipment degradation and, in some cases, manhole fires or explosions.

In a generally warmer climate, the steam system could experience significant decreases in winter energy sales for heating. There could be up to a 33% decrease by 2050 and a 49% decrease by

2080. Similarly, under the RCP 8.5 scenario, winter gas peak load is projected to decrease by 891 Mlb/hr in the winter of 2050 compared to the base case.

## Adaptation Options for the Steam System

To determine when to implement various adaptation strategies, Con Edison could track climate trends, including TV, precipitation, sea level rise and storm surge, and extreme events, as described in prior vulnerability and adaptation sections.

The Study team suggests that Con Edison could continue to work collaboratively with other city actors on initiatives that could help strengthen the resilience of the steam system. Specifically, the company could take measures, including the following:

- Strengthen collaboration with the city to improve citywide stormwater design to alleviate flooding impacts and make adaptation measures implemented by Con Edison, such as drain pumps at manholes, more effective.
- Discuss ways to minimize salt use during the winter.
- Incorporate considerations of New York City initiatives in coastal resiliency plans for lower Manhattan to re-evaluate Con Edison's storm response plans and stages of pre-emptive main shutoffs.

In addition to engaging in these monitoring and coordination efforts, the company could also consider taking measures to address physical vulnerabilities in existing infrastructure by strategically investing in the system. Physical measures developed by the Study team are listed in Table 8.

**Table 8** ■ Physical adaptation options for steam commodities

| Hazard | Asset | Adaptation Option | Implementation Timeframe | Signpost or Threshold |
|---|---|---|---|---|
| Extreme Hurricane (e.g., Category 4) | Generation System | Invest in additional storm hardening investment measures to protect generation sites against extreme hurricane-driven storm surge. Leverage new innovations and advancements in flood protection over time and raise moated walls around current generation sites. | 2050 | When sea level rise exceeds 1 foot |
| | Distribution System | Continue to segment the steam system to limit customer outages in flood-prone areas. | In preparation for a Category 4 hurricane | Increased frequency and severity of storms, including from science-based projections |
| | Distribution System | Expand programs to harden steam mains (waterproofing pipes and raising mains). | In preparation for a Category 4 hurricane | Increased frequency and severity of storms, including from science-based projections |
| | | Pre-stage a greater number of drain pumps at critical or flood-prone manholes. | | |

As it is neither practical nor feasible for Con Edison to build resilience to the point that its steam system can fully withstand the impacts of extreme events, Con Edison could also consider implementing additional strategies to better absorb and recover from impacts, such as improving systems for crowd-sourcing steam system leak detection.

# Moving Towards Implementation

## Initial Climate Projection Design Pathway

Implementation of adaptation options to mitigate vulnerabilities requires clear climate design guidelines that incorporate forward-looking regional climate change projections. To this end, the Study team suggests that Con Edison could establish an "initial climate projection design pathway" that considers appropriate risk tolerance levels within the range of climate change projections. The initial climate projection design pathway is meant to guide preliminary planning and investments until and if Con Edison can refine the pathway to reflect new climate projections with reduced uncertainties, changes to Con Edison's operating environment, and changes in city guidance. The following section outlines an adaptive management approach that allows Con Edison to monitor, manage, and design to acceptable levels of climate risk through time.

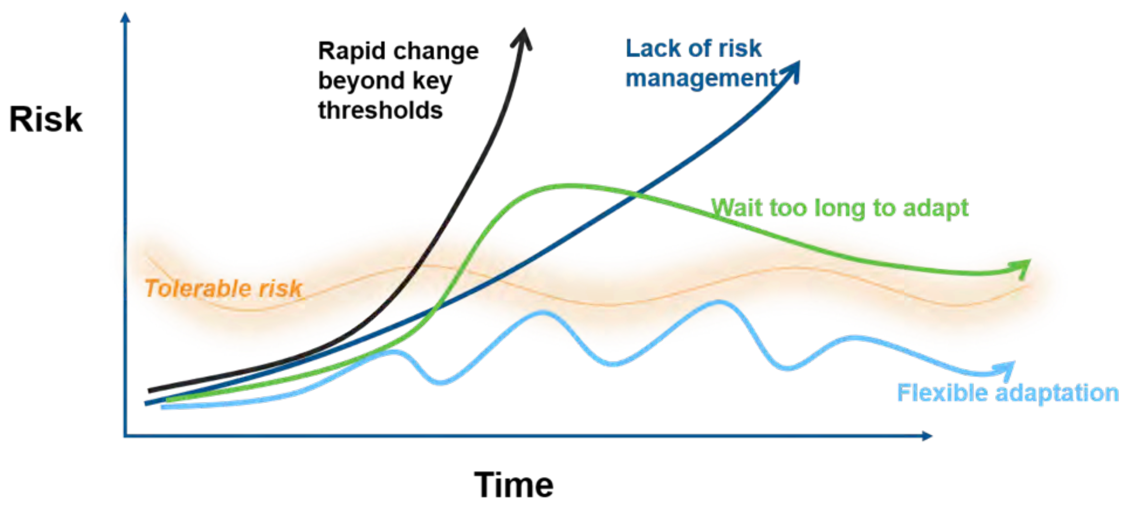
As an initial climate projection design pathway for decisions that require it, Con Edison will follow the conservative precedent set by the city's climate resiliency design standards (e.g., Mayor's Office of Recovery and Resiliency, 2019), combined with the state-of-the-art climate projections produced for this Study. Corresponding to city guidance, the same pathway may not apply uniformly across different climate change projections and hazards. More specifically, multiple climate projection design pathways may be required to address differences in the risk tolerance and projection uncertainty associated with different climate hazards. Under this framework, initial pathways could use the 50th percentile merged RCP 4.5 and 8.5 projections for sea level rise and high-end 90th percentile merged RCP 4.5 and 8.5 projections for heat and precipitation. Climate projection design pathways will be finalized for Con Edison's Climate Change Implementation Plan.

Alternative considerations are necessary to inform pathways for rare and difficult-to-model extreme events without probabilistic projections, such as 1-in-100-year heat waves and strong, multi-faceted hurricanes. Rather than prescribing statements of probability, these types of extremes require the blending of plausible worst-case scenarios from a climate perspective with stakeholder-driven worst-case scenarios from an impact perspective. Until climate modeling can better resolve and simulate these types of rare extreme events, the union of these two perspectives is critical for determining acceptable risk tolerance levels and setting initial pathways.

## Flexible Adaptation Pathways Approach

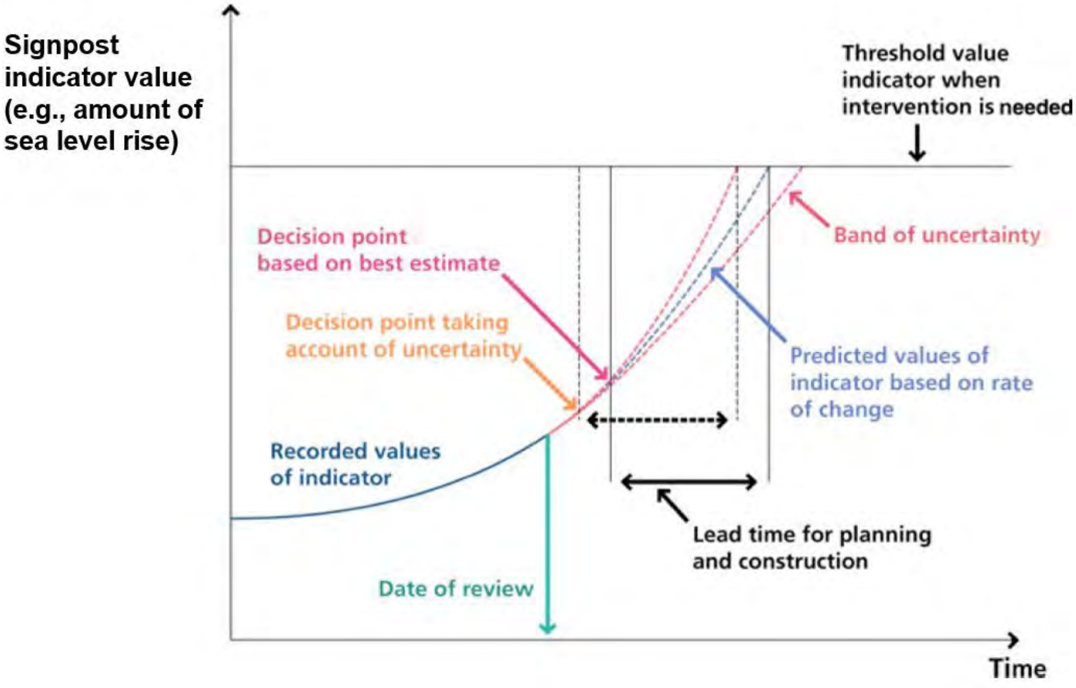
While the initial climate design pathway can inform asset design, a complementary approach is needed to ensure resilience over the lifetime of that asset. A flexible and adaptive approach will allow Con Edison to manage risks from climate change at acceptable levels, despite uncertainties about future conditions. The flexible adaptation pathways approach ensures continued adaptability over time as more information about climate change and external conditions is learned. Figure 23 depicts how flexible adaptation pathways are used to maintain tolerable levels of risk.

**Figure 23** ■ Flexible adaptation pathways in the context of tolerable risk and risk management challenges to non-flexible adaptation. Adapted from Rosenzweig & Solecki, 2014.




Con Edison will need to consistently track changing conditions over time to identify when additional adaptation strategies are required. This approach relies on (1) monitoring indicators ("signposts") related to climate conditions, climate impacts, and external conditions that affect system resilience, and (2) pre-determined thresholds to signal the need for a change in risk management approaches ("transformation points"). This approach can support decisions on when, where, and how Con Edison can take action to continue to manage its climate risks at an acceptable level. Figure 24 depicts how a signpost indicator and a predefined threshold can be applied in the adaptation pathways approach to inform the timing of action given uncertainty.

**Figure 24** ■ Schematic diagram of how an indicator of change for a particular signpost (e.g., amount of sea level rise) informs decision lead times that take into account uncertainty (Ranger et al., 2012).




Con Edison is already familiar with monitoring signposts to manage planning uncertainties and guide adjustments to its Electric, Gas, and Steam Long Range Plans.[20] Con Edison currently monitors signposts related to the pace of technology innovation (e.g., energy management technologies), the nature of regulation and legislation (e.g., new or revised greenhouse gas reduction policy targets), and the future of the economy (e.g., higher economic growth and impacts on demand), among others. In addition, the flexible adaptation pathways approach to manage climate change risks has been applied more widely by New York City and New York State (New York City Mayor's Office of Resiliency, 2019; Rosenzweig & Solecki, 2014) and utilities and infrastructure agencies across the United States, including San Diego Gas & Electric (Bruzgul et al., 2018; SDG&E, 2019) and Los Angeles Metro (Metro ECSD, 2019).

This flexible adaptation pathways approach allows Con Edison to develop an adaptation implementation plan in the near term, while adjusting adaptation strategies based on the actual climate conditions that emerge, thus reducing the cost of managing uncertainty. Under this adaptive approach, resilience measures can be sequenced over time to respond to changing conditions. For example, Con Edison may identify actions to implement now that protect against near-term climate changes and actions that are low and no regret, while leaving options open to protect against the wide range of plausible changes emerging later in the century. This implementation approach is preferred to implementing actions now that are optimized for present-day conditions or a single future outcome that ignores uncertainty.

[20] Long Range Plans are available at: https://www.coned.com/en/our-energy-future/our-energy-vision/long-range-plans

## Illustrative Adaptation Pathway: Sea Level Rise Adaptation for Substation in FEMA + 3’ Floodplain

Flexible adaptation pathways could be developed for guiding the management and protection of specific assets or types of assets. Here, we consider a hypothetical electric substation that is potentially vulnerable to sea level rise, as it is located within the FEMA + 3’ floodplain (and, as such, is protected up to FEMA + 3’ flood heights based on Con Edison’s current design standards). This adaptation pathway is presented as *illustrative*; while it is grounded in the types of strategies that Con Edison would use for substation flood defense, a ready-to-implement pathway for implementation would require site-specific analysis and may differ from this configuration.

**Figure 25 ■** Illustrative flexible adaptation pathway for a hypothetical Con Edison substation in a current FEMA + 3' floodplain

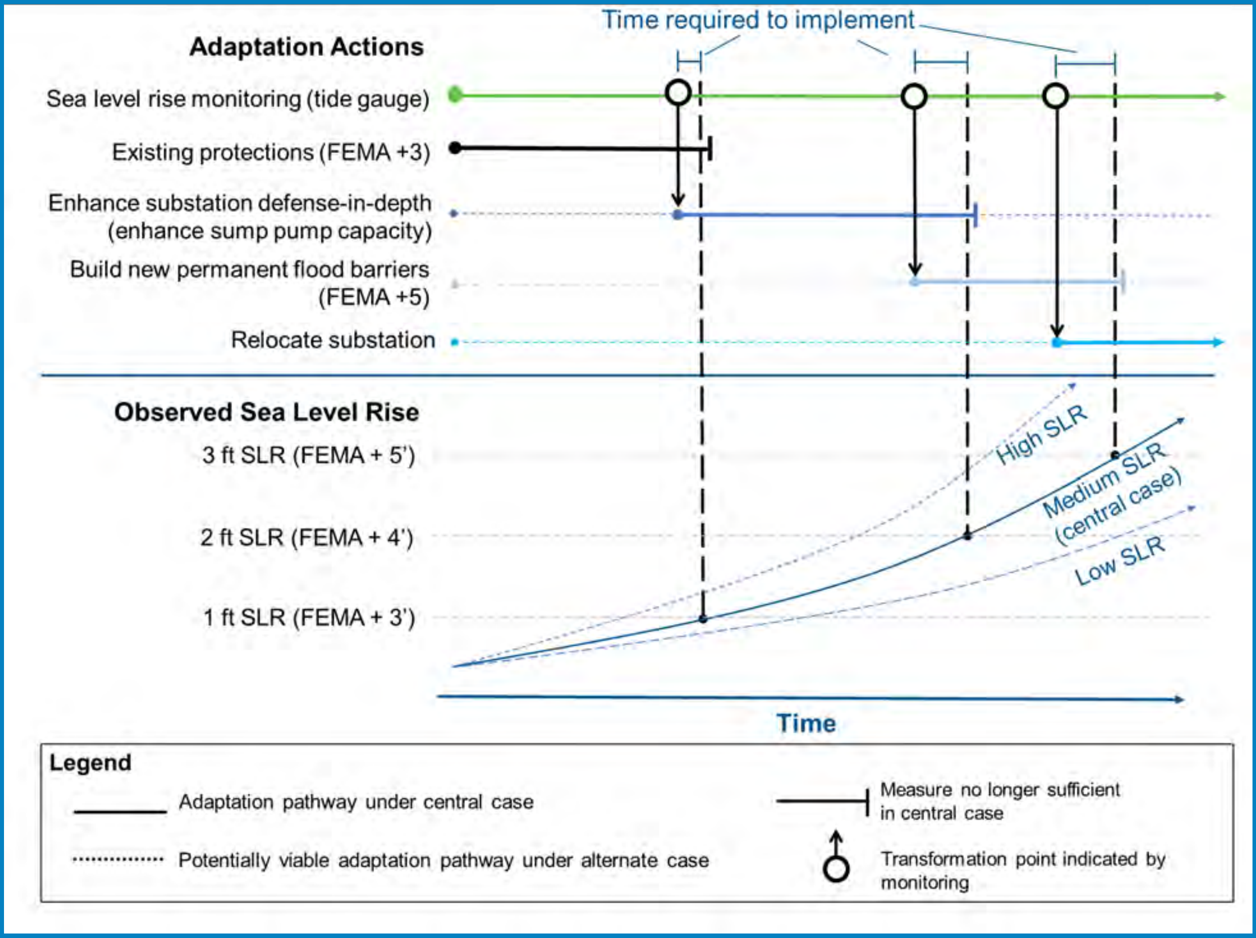


Figure 25 illustrates how the implementation of adaptation actions can be phased over time, with the implementation of new measures being triggered by observed sea level rise in excess of certain thresholds (transformation points). The timing of these transformation points is indicated by monitoring the rate of sea level rise at a local tide gauge (green line). Transformation points are set based on the point at which Con Edison needs to take action in order to implement a higher standard of protection before existing protections become insufficient.

In this adaptation pathway diagram, the implementation schedule of adaptation measures is illustrated based on a "central" sea level rise case. Measures based on this central scenario are illustrated with solid lines. If the actual pace of sea level rise deviates from the central case, monitoring of sea level rise may necessitate an accelerated or delayed implementation schedule

In this example, it is assumed that the substation already has existing protections to FEMA + 3′ based on Con Edison's post-Superstorm Sandy hardening measures (black line). However, these protections will no longer be sufficient to provide the requisite 2 feet of freeboard under a 100-year flood scenario once sea level rise surpasses 1 foot.

- A trigger slightly under 1 foot leads to the first adaptation option, which is to supplement the substation's defense-in-depth strategy with additional sump pump capacity.
- The second adaptation option is triggered when sea level rise approaches 2 feet, and includes building new permanent flood barriers to a FEMA + 5′ level.
- The final adaptation option, relocating the substation entirely, is triggered when sea level rise approaches 3 feet.

Each trigger is far enough in advance of the critical risk threshold (each foot of sea level rise, in this case) to have time for full implementation of the adaptation option.

Such a flexible adaptation pathway can allow Con Edison to better manage the costs of adaptation in the face of uncertainty, facilitating a prudent approach that avoids adapting too early or too late.

Signposts provide information that is critical for adaptive management decisions. Broad categories of signposts that Con Edison could consider monitoring include:

- **Climate variable observations and best available climate projections:** An awareness of recent and present climate conditions and their rates of change are key when determining potential asset exposure and risk. As described above, Con Edison currently operates a number of stations that monitor climate variables and is finalizing plans to expand the number of monitoring locations. Furthermore, access to the most recent and best available climate projections and expert knowledge is critical when updating plans for potential future scenarios as the science advances. In some cases, thresholds for action under climate variable and projection signposts may be determined by how quickly changes in climate conditions are approaching existing design or operational specifications.
- **Climate impacts:** Con Edison is already experiencing extreme weather and climate impacts to assets, operations and internal processes, and customers. Recognizing the risks, Con Edison is already conducting monitoring to identify areas of heightened vulnerability in its systems. Continued monitoring and evaluation of highest risk assets for impacts or near impacts can provide information about when and where additional adaptation options may be required.
- **Policy, societal, and economic conditions:** Evolving external conditions may affect climate-related decision making and areas of need throughout the service territory. Con Edison is already monitoring signposts for external conditions related to policies, society, and economies as part of its long-range plans. Additional external conditions may shift with a changing climate, such as adaptation strategies and investments led by the city.

The Study team identified a set of example signposts within each category, summarized in Table 9. Con Edison could consider coordinating with the city on NPCC's proposed New York City Climate Change Resilience Indicators and Monitoring System (Blake et al., 2019), where overlap and efficiencies in monitoring signposts may exist.

**Table 9** ■ Example signposts for a flexible adaptation pathways approach

| Category | Example Signposts |
|---|---|
| Climate variable observations and best available climate projections | • *Chronic variables:* Rate of change in TV, cooling degree-days, heating degree-days, sea levels, etc. relative to historical<br>• *Extreme weather variables:* Number of days overheat index thresholds, storm surge levels, frequency of various storm types in the greater region, wind speeds, heat wave intensity and duration, intense precipitation levels, etc.<br>• Updates to the best available climate projections: NPCC, IPCC, National Climate Assessment, etc. |
| Climate impacts | • *Assets:* Extent and magnitude of the costs of keystone asset damages (e.g., substations or power lines downed), damages incurred by events with different combinations of extreme weather, etc.<br>• *Operations and internal processes:* Frequency of heat-related contingencies in the network and non-network systems, etc.<br>• *Customers:* Number, spatial extent, and duration of outages caused by extreme weather, especially noting outages experienced by critical infrastructure and interdependent systems, etc. |
| Policy, societal, and economic conditions | • *Policy:* Updates to New York City design guidelines, etc.<br>• *Societal:* Community-scale flood protection strategies led by New York City (e.g., East Side Coastal Resiliency Project), population shifts (e.g., retreat), etc.<br>• *Economic:* Insurance prices and availability, etc. |

## Selecting Cost-Effective Solutions

As outlined in this Study, adapting to climate change will require investments in infrastructure and processes. Although some adaptation will be achieved through co-benefits from investments that Con Edison makes under existing processes, such as using distributed energy resources to meet growing electricity demand, other adaptation will require investments over and above those previously planned. The costs of those investments will ultimately be reflected in customers' bills. In order to minimize the financial impact of adapting to climate change, a cost-effective resilience planning process should identify a target level of resilience along with associated metrics, strike a balance between proactive and reactive spending, consider both the costs and benefits to customers, and select adaptation strategies that provide optimal benefit at the lowest cost.

As the energy industry grapples with how best to build resilience to the changing climate, the issue of how to quantify the resilience of energy systems is front and center. There is currently no standard *set of metrics* for the resilience of energy systems. A 2017 report from the National Academies of Sciences, Engineering, and Medicine found that "there are no generally agreed-upon resilience metrics [for the electricity sector] that are widely used today," also noting a contrast with the well-established set of electricity reliability metrics (NAS, 2017).

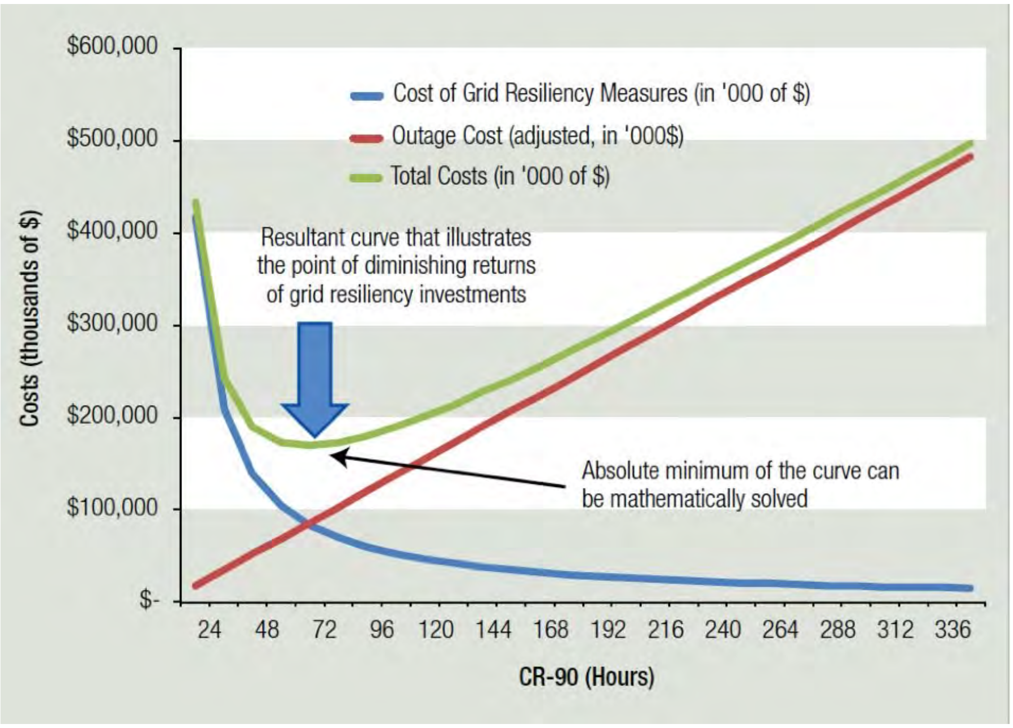
While there are a wide variety of energy resilience metrics that have been proposed or piloted in various contexts, most of these metrics fit within one of two broad categories. *Performance-based* metrics seek to quantify the resilience of the system through measurement of infrastructure performance during actual or modeled disruptive events. *Attribute-based* metrics, on the other hand, measure the presence of characteristics or features that are known or predicted to increase resilience performance in the event of a disruption. (Vugrin, Castillo, & Silva-Monroy, 2017).

Con Edison's storm hardening investments after Superstorm Sandy were guided by a combination of performance-based metrics, such as "past performance" in the selective undergrounding of feeders, and attribute-based metrics, such as "reducing the number of customers served by a single circuit to fewer than 500 customers," and adding "isolation devices to spurs and sub-spurs with open wire that are more than 2 spans in length" (Con Edison, 2013). Since the development of metrics is an active area of research and discussion, Con Edison could keep abreast of industry advances in resilience metrics for energy systems and incorporate those advances, where applicable, into its planning framework.

Even after a resilience metric(s) is selected, the question of exactly *how much* to spend on resilience or what the *right* level of resilience is, remains. One approach is to compare the societal cost of an outage against the cost of resiliency measures to shorten that outage. The total cost curve developed by ICF's Mihlmester and Kumaraswamy (Figure 26) is one example of such an approach (Mihlmester & Kumaraswamy, 2013). It shows for a hypothetical utility the post-outage time needed to restore service to 90% of customers, known in the industry as "CR-90." In this case, the lowest total costs, combining customer outage and grid-hardening costs, would be about $169 million for a 65-hour CR-90 restoration time. The graph also shows that getting the CR-90 time to less than a day would cost more than twice that amount.

For Con Edison, the "right" level of resiliency investment will be strongly linked to the climate projection design pathway selected for each of the climate stressors identified for resiliency planning.

**Figure 26** ■ Total cost of resiliency (Mihlmester & Kumaraswamy, 2013)




Utilities have historically *reacted* to events, primarily because they lacked relevant climate projections and clear guidance or best practices for a methodology necessary to inform *proactive* adaptation and resiliency investments in infrastructure (California Energy Commission, 2018). Similarly, prior to conducting this study, Con Edison had limited information to guide proactive investments. The U.S. Department of Energy's North American Energy Resilience Model (U.S. DOE, 2019) highlights the need to "transition from the current reactive state-of-practice to a new energy planning and operations paradigm in which we proactively anticipate damage to energy system equipment, predict associated outages and lack of service, and recommend optimal mitigation strategies."

The Study team has described an overarching resilience management framework in Figure 12, designed to minimize the impacts of extreme events throughout asset life cycles. The framework considers how the system can withstand, absorb, recover, and adapt to risks posed by extreme events. To succeed, each measure of a resilient system requires *proactive planning and investments*.

Consideration of the *costs and benefits to customers* is a key component in the selection of adaptation options. Con Edison's capital budget cycle currently considers costs and benefits through an investment optimization and management process that compares the wide array of capital investments the company makes across its various business units. The process calculates a "strategic value" for each project to compare the benefit of investing in one capital project or program over another and to ensure that spend is in alignment with the company's corporate strategy. The strategic value is conveyed by a set of strategic drivers, each with relative weights, based on the company's long-term objectives. The strategic value of each capital project is assessed against that of other projects, and an optimized portfolio of capital projects is generated. While the strategic drivers include *reliability* and customer satisfaction components, the drivers do not include or consider the *resiliency* benefit of a project.

Con Edison developed and used a cost-benefit calculation model to prioritize storm hardening investments after Superstorm Sandy. The model estimated "the vulnerability of individual electric system assets based on the impact of electric system damage to customers and supporting critical infrastructure, the duration of an electric service outage, the likelihood of those assets being affected by either flooding or wind damage, and the reduction in vulnerability of those assets because of storm hardening initiatives." (Con Edison, 2014)

Con Edison's current distribution system planning process includes an evaluation of customer benefits resulting from investments. Con Edison's Distributed System Implementation Plan (DSIP) (Con Edison, 2016) includes the consideration of distributed energy resources as one option to meeting growing demand. As part of Con Edison's DSIP, the company has developed a Benefit Cost Analysis (BCA) Handbook that describes how to calculate individual benefits and costs. The BCA includes consideration of the unit cost of a particular option, per megawatt of delivery capacity, as well as an option's "social cost." Social cost accounts for the monetization of air pollution and carbon dioxide, using 20-year forecasts of marginal energy prices, the cost of complying with regulatory programs for constraining these pollutants, and the price paid for renewable energy credits. The social cost metric also qualitatively accounts for avoided water and land impacts. Beyond these environmental aspects, social cost accounts for net avoided restoration and outage costs to Con Edison, as well as net non-energy benefits (such as avoided service terminations, avoided uncollectable bills, and avoided noise and odor impacts).

This Study illustrates the use of multi-criteria analysis to compare criteria that may be difficult to quantify or monetize, or that may not be effectively highlighted in the financial analysis. This process identified additional complementary metrics that could be included in Con Edison's planning and budget prioritization process to account for uncertainty in climate outcomes. These metrics fall into two categories: co-benefits and adaptation benefits. Under a non-stationary climate, co-benefits (environmental, reputational, safety, and customer financial benefits) can help planners more comprehensively evaluate response options considering the additional challenges that climate change can pose on the system. In addition, consideration of adaptation benefits (flexibility, reversibility, robustness, proven technology, and customer's resilience) support long-term planning under climate uncertainty. These metrics allow for effective implementation of adaptation measures over time to achieve resilience. Con Edison's current processes include some of the metrics identified in the multi-criteria analysis (environmental and safety) but not others (customer's resilience and reversibility). Con Edison could work to incorporate this wider set of metrics as it incorporates resiliency planning into its broader capital budgeting process.

## Key Issues to Be Addressed for Effective Implementation

### Changes in the Policy/Regulatory and Operating Environment

Changes in the policy/regulatory and operating environment other than climate change were not accounted for in this Study but will be an important consideration when moving toward implementation. For example, the prioritization of adaptation strategies, and even the understanding of vulnerabilities, will need to consider these other drivers of change. Likewise, as Con Edison undertakes studies on how these factors will impact its business, climate change impacts could be factored into those studies. Some examples of possible changes in Con Edison's operating environment include:

- **Climate change and clean energy targets:** New York State and New York City have both adopted ambitious greenhouse gas emissions reduction targets (State of New York, 2019; City of New York, 2014), which will drive changes in the adoption of renewables, transportation electrification, energy storage, and so forth. It will also impact relative demand across the commodities (e.g., decreasing gas demand and increasing electricity demand).

- **Technological advances:** Advances in solar photovoltaics, energy storage, electric vehicles, and electrification of space heating are changing how and where electricity is generated and used.
- **Customer response to climate change impacts:** Customers will also have to respond to climate change impacts. This may include shifting away from flooded coastlines (depending on city-scale investments in coastal protection) and, with it, shifting demand away from portions of Con Edison's system.

## Coordination with External Entities

Another critical need for effective implementation is coordination with external entities, including the City of New York and Westchester County, industry groups, equipment manufacturers, and others. Con Edison has limited authority to address certain vulnerabilities, such as the capacity of the city's stormwater system, so coordination is necessary for developing a more resilient system. In addition, coordination is needed to ensure that Con Edison is not over-investing in locations that the city plans to protect or retreat from. This project seeded the necessary relationships; however, the continuation of the interactions will need to be specified in the governance section of the upcoming implementation plan.

## Establishing a Reporting and Governance Structure

Con Edison will need a continuing approach to updating stakeholders on climate risk management progress. Of the various reporting options, many companies are opting to follow the relatively new framework outlined by the Task Force on Climate-Related Financial Disclosures (TCFD).[21] This framework emphasizes the need to assess both the physical risks of climate change, which is covered in this study, as well as the risks and opportunities presented by transition to a low-carbon economy. It requires consideration of the financial implications of the risks and opportunities, as well as a measurable risk management plan that is integrated with a strong governance structure.

Two risks that were not explored in this study, but would fit well in the TCFD framework, include:

- **Costs and penalizations from service failure and outages:** Costs associated with an outage event include restoration; collateral damage; customer claims; penalties, fines, audits, remediation, and reporting; and the financial impact of lost confidence. For example, in 2007, Con Edison was penalized $18 million for its 2006 service disruptions, which included a 9-day blackout in western Queens.
- **Credit rating:** Increasingly frequent and intense extreme weather events could also impact credit rating risks and insurance liabilities. Credit rating agencies like Standard & Poor's and Moody's have added "resiliency" as a component of their rating criteria, indicating the relevance of climate risk for creditworthiness (Shafroth, 2016). Similarly, utilities may be increasingly choosing to retain a higher level of insurance to cope with more frequent and destructive weather-related events. However, a higher level of insurance protection leads to higher costs that may ultimately be reflected on customers' bills. Thus, while not as visible as physical asset or planning vulnerabilities, climate risks related to credit and insurance can have an impact on the utility.

Establishing a governance structure will be crucial for the successful continuation of Con Edison's climate change adaptation work. The governance structure can be used to encourage and track progress on the implementation of adaptation strategies (i.e., performance against set metrics and targets), ensure specific

[21] For more information on the Task Force on Climate-Related Financial Disclosures, see https://www.fsb-tcfd.org/

people are on point for monitoring and implementing various strategies, and establish a frequency and process for reporting on risks and adaptation actions from individual employees to senior managers to Con Edison's board of directors.

## Next Steps

As a next step from this Study, Con Edison will develop a detailed Climate Change Implementation Plan to operationalize the suggestions from this Climate Change Vulnerability Study. The implementation plan will:

- Review the Study and investigate whether recent progress in climate science may warrant inclusion.
- Select climate change pathway(s) to incorporate into design standards and procedures.
- Establish life cycle tables that provide timeframes of reference climate variables through 2080.
- Aggregate input from subject matter experts on changes required for specifications/procedures and choices for risk mitigation measures.
- Develop a timeline and written plan for the implementation of risk mitigation measures.
- Identify the scope and cost within the 5-year capital plan and 10- and 20-year long-range plans.
- Establish signposts for the re-evaluation of measure installation schedules.
- Conduct periodic progress meetings for external stakeholders.
- Recommend a governance structure for climate change monitoring and updating.

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# APPENDICES

# Appendices

To inform the conclusions of this Study, the Study team undertook a series of in-depth vulnerability assessments corresponding to the climate hazards representing outsized risks to Con Edison: temperature, humidity, precipitation, sea level rise, and extreme events. These are included as appendices. Each appendix includes detailed historical and projected climate conditions; corresponding climate-driven vulnerabilities to operations, planning, and infrastructure across the company's electric, gas, and steam systems; and potential adaptation strategies to mitigate vulnerabilities.

For each hazard, the Study team collaborated with Con Edison subject matter experts to conduct a rapid screen of the sensitivity of operations, planning, and infrastructure to support a risk-first approach. Vulnerabilities were then selected for more detailed analyses, which focused on understanding asset vulnerabilities to climate change and, in turn, relevant adaptation options and evaluation of their costs and co-benefits. These analyses informed the development of flexible solutions and signposts to guide implementation of potential adaptation options through time.

Ultimately, the five appendices provide key context for the climate science, vulnerabilities, and adaptation strategies discussed in this report, and as such, can be referenced for more comprehensive information in each subject area.

- **Appendix 1 – Temperature:** Identifies how projected gradual trends in increasing temperature may affect operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business.
- **Appendix 2 – Humidity, Temperature Variable, and Load:** Addresses climate variables—humidity (expressed through wet bulb temperature), heat waves, cooling degree-days, heating degree-days, and the combination of projected changes in wet and dry bulb temperatures—that have a direct effect on system loads and reliability. These variables are also specifically addressed in specifications and procedures associated with upgrading system capacity and maintaining system reliability.
- **Appendix 3 – Changes in Precipitation Patterns:** Discusses the potential for climate-driven changes in rainfall and frozen precipitation in Con Edison's service territory, and the potential impacts of those changes on Con Edison's assets and operations.
- **Appendix 4 – Sea Level Rise and Changes in Coastal Storm Surge Potential:** Examines the ways in which changes in sea level may affect operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business.
- **Appendix 5 – Extreme Events:** Describes how extreme weather events (hurricanes, nor'easters, and heat waves), as well as concurrent or consecutive extreme events, may become more frequent and severe due to climate change, and considers their potential impact on operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business over the coming century.

**South Carolina Public Service Commission**

**Docket No. 2019-224-E**
**Docket No. 2019-225-E**

**Exhibit TF-6**

**Duke Energy Carolinas and Duke Energy Progress Response to Vote Solar Data Request 2-7**

**DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

**Request**:

Please refer to the IRP Report at page 18, which states "Factors such as changing cost of capital will also influence future energy costs and will be incorporated into IRP forecasts as market conditions evolve."

a) Does the Company agree that the cost of capital available to the operating companies is affected at least in part by risks associated with the companies' generation portfolio?
b) Does the Company agree that the operating companies' generation portfolio has at least some exposure to climate-related physical, economic, and regulatory risks, as identified in Duke Energy's 2020 Climate Report?
c) Does the Company agree that, holding all other things equal, an increase in the Companies' cost of capital would result in a greater cumulative present-value revenue requirement?

**Response**:

a) The sentence referred to is part of the Customer Financial Impacts section of the IRP report, and is simply making the point that changes in the cost of capital (in addition to other changes) will affect the estimated customer bill. If financial markets perceive that relevant risks that stem from the companies' generation portfolio has changed, then the Company agrees that an impact on the cost of capital is possible.

b) All of the factors cited could potentially impact the future generation portfolio.

c) Not necessarily. A higher cost of capital would imply higher future capital costs. However, a higher cost of capital would also imply a higher discount rate, which leads to a greater discounting effect per dollar of future cost. More assumptions such as inflation rate, timing of the project, and other cost impacts would be needed to determine the impact on cumulative present value of revenue requirement.

Person responsible: John Freund, Principal Structuring Analyst